COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218	)	CASE NO. 2002-00475

O R D E R

On August 25, 2003, the Commission granted the requests of Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") and PJM Interconnection, L.L.C. ("PJM") for rehearing of the Commission's July 17, 2003 Order which denied Kentucky Power's application to transfer functional control of its transmission assets to PJM.

Kentucky Power owns facilities that are used to generate, transmit, and distribute electricity to 174,000 retail customers in 20 counties in eastern Kentucky. Thus, Kentucky Power is a utility as defined by KRS 278.010(3)(a) and is subject to the regulatory jurisdiction of this Commission. PJM is an independent transmission operator that has been approved by the Federal Energy Regulatory Commission ("FERC") as a regional transmission organization ("RTO"). PJM is subject to the regulatory jurisdiction of the FERC.

Kentucky Power's request to transfer functional control of its transmission facilities to PJM falls within the purview of KRS 278.218. Enacted by the Kentucky General Assembly in 2002, this statute prohibits a utility from transferring ownership or control of its assets unless it has received the prior approval of the Commission. The standard of review established by the statute is that, "The Commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest." This statute, which applies to the transfer of ownership or control of assets, was enacted to supplement the Commission's then-existing authority under KRS 278.020(4) and 278.020(5) to review and approve the transfer of ownership or control of a utility.

Kentucky Power is a wholly owned subsidiary of American Electric Power Company ("AEP"), a multi-state registered public utility holding company. For many years AEP has owned five electric utility companies in the Midwest that collectively provide service to parts of the following seven states: Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP's operations in the Midwest are now collectively referred to as "AEP-East."

In 1998, AEP announced a merger with Central and South West Corporation ("CSW"). CSW owned four utilities that operated in parts of Arkansas, Louisiana, Oklahoma, and Texas. Since the merger with AEP, the territory formerly served by CSW is now commonly known as "AEP-West."

As part of FERC's approval process for the AEP/CSW merger, AEP negotiated a settlement with certain Ohio intervenors. The settlement included an obligation that

AEP-East join an RTO, an obligation adopted by FERC and expressed as a condition of the merger.[1]

CASE HISTORY

Kentucky Power filed its application on December 19, 2002 requesting approval to transfer functional control of its transmission assets to PJM. The Attorney General of the Commonwealth of Kentucky, Kentucky Industrial Utility Customers, Inc., and PJM requested and were granted intervention. Following a procedural schedule that provided for discovery and the filing of prepared direct testimony, a public hearing was held on March 25, 2003. Post-hearing briefs were filed and the Commission issued an Order on July 17, 2003 denying Kentucky Power's application.

The Commission's denial of Kentucky Power's application was based, in part, on the absence of any Kentucky-specific cost/benefit analysis to demonstrate that the proposed transaction was in the public interest. The evidence of record at that time did not show that Kentucky Power's membership in PJM would produce any benefits for the public without adversely affecting the utility or its quality of service. To the contrary, the record showed significant, quantifiable annual membership costs, with no quantifiable benefits flowing to Kentucky Power or its ratepayers. The July 17, 2003 Order also discussed a number of other reasons why PJM membership was not in the public interest, including the apparent inability of PJM to comply with KRS 278.214, which requires, in certain specified circumstances, transmission priority for retail service.

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[1] *American Electric Power Co. & Cent. & S.W. Corp.*, 90 F.E.R.C. ¶ 61,242 (Mar. 15, 2000), *aff'd sub nom, Wabash Valley Power Ass'n v. FERC,* 268 F.3d 1105 (D.C. Cir. 2001).

The Commission subsequently granted rehearing to afford Kentucky Power an opportunity to provide a Kentucky Power-specific cost/benefit study. Rehearing was also granted to PJM on the cost/benefit issue, as well as on issues relating to PJM's operational rules and requirements. A procedural schedule was then established which provided for the filing by Kentucky Power and PJM of cost/benefit studies and prepared direct testimony. Subsequent to filing those documents, the Commission convened a series of informal conferences among the parties to clarify and refine the issues. As a result of these conferences and the cooperative efforts of the parties, an Agreed Stipulation ("Stipulation") was filed on April 19, 2004.

FERC PROCEEDINGS

FERC, in furtherance of its decision to condition the AEP/CSW merger on RTO membership, approved the transfer of functional control of the transmission assets of the AEP-East utilities, including Kentucky Power to PJM, on April 1, 2003. Subsequent to this Commission's decision to deny Kentucky Power's request to join PJM, FERC initiated a proceeding to determine what options might be available to resolve the conflict between FERC's position and that of Kentucky (and Virginia, which by state law is unable to approve RTO membership prior to June 30, 2004). FERC then issued preliminary conclusions that the decision of this Commission (and the Virginia law) was preventing the economic utilization of facilities and resources, as those terms are used in Section 205(a) of the Public Utilities Regulatory Policy Act of 1978 ("PURPA"), and set for hearing that issue and whether FERC should invoke that Section of PURPA to preempt the decision of this Commission (and the law of Virginia). This Commission is an active participant in that FERC proceeding, which is docketed as FERC Case No. ER03-262-009.

SUMMARY OF STIPULATION

The Stipulation, attached hereto as Appendix A, has been signed by all parties to this case. It recommends that the Commission now approve Kentucky Power's application for authority to transfer functional control of its transmission facilities to PJM, subject to specified terms and conditions. Those terms and conditions address, among other issues, the findings set forth in the Commission's July 17, 2003 Order regarding the voluntary nature of PJM's energy market, our continuing authority to protect retail customers, and PJM's curtailment protocols.[2] In addition, the parties recommend that the Commission file the Stipulation with FERC as an offer of full settlement of Docket No. ER03-262-009, as applied to the Commonwealth of Kentucky.[3]

COMMISSION ANALYSIS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that the Stipulation, in conjunction with Kentucky Power's cost/benefit analysis, adequately addresses the issues discussed in our July 17, 2003 Order as the basis for denying Kentucky Power's application. That Order noted the absence of a Kentucky Power-specific cost/benefit analysis and discounted the analysis filed by PJM because there was no demonstration that the net benefits it showed for AEP-East would result in net benefits for Kentucky Power itself. The cost/benefit study filed on rehearing by Kentucky Power estimated the net economic impact of PJM membership for the

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[2] Stipulation, Paragraphs 1, 3, and 5.

[3] Stipulation, Paragraph 10.

period 2004-2008. The study compared a base case scenario in which Kentucky Power and AEP were not part of PJM to a scenario in which they are fully integrated into PJM. The study was based on a simulated dispatch analysis conducted for AEP by Cambridge Energy Research Associates using the General Electric Multi-Area Production Simulator production cost simulation model.[4]

The benefits identified in the cost/benefit study are: (1) greater off-system sales profits; (2) net revenues from the sale of financial rights to transmit power on the AEP-East transmission system; and (3) avoided contract costs for services that will now be performed by PJM. The costs included in the analysis consist of approximately $3.9 million per year as Kentucky Power's allocated share of the PJM administrative costs that will be borne by AEP. Total nominal benefits to Kentucky Power over the 5-year period are estimated to be $33.1 million, with estimated net benefits of $13.4 million after recognizing Kentucky Power's share of the PJM administrative costs.[5] Of the total benefits identified for the 5-year period, $24.3 million are attributed directly to Kentucky Power's increased profits from off-system sales. These off-system sales profits are shared with retail customers through Kentucky Power's monthly system sales clause.

The July 17, 2003 Order also expressed concern that membership in PJM could result in a mandatory requirement that Kentucky Power sell the output of its generation

[4] PJM used this same model in preparing the cost/benefit analysis of AEP-East which it presented as part of its original testimony.

[5] Baker Testimony on Rehearing, Exhibit JCB-1.

into the PJM market.[6] Paragraph 1 of the Stipulation affirms the voluntary nature of the PJM energy market for purchases and sales of energy and affirms that AEP can elect to either participate in PJM's spot energy market to meet Kentucky Power's native load energy requirements, contract bilaterally with other entities to supply energy, or schedule its own generation to meet those requirements.

The Stipulation specifies that AEP, on behalf of Kentucky Power, will retain its existing rights to "self-schedule" its resources to meet its native load's energy needs.[7] The Stipulation also affirms that this Commission will retain its existing authority to conduct fuel adjustment and base rate proceedings to investigate and establish the level of energy and generation costs recoverable in Kentucky Power's retail rates. This affirmation of this Commission's authority, coupled with the voluntary nature of PJM's energy market for meeting Kentucky Power's native load energy requirements, provides adequate assurances that Kentucky Power's retail energy costs will continue to be fair, reasonable, and relatively stable over time, and not subject to market price variations.

Another reason for the Commission's denial of PJM membership was that the transfer of control of Kentucky Power's transmission assets to PJM would be inconsistent with the Commission's duty to enforce KRS 278.214, which provides that retail customers be the last to suffer curtailment or interruption of service resulting from an electric system emergency. Pursuant to Paragraph 3a of the Stipulation, PJM will not direct AEP or Kentucky Power to interrupt retail customers as a result of capacity

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[6] July 17, 2003 Order at 20.

[7] In the event that FERC proposes mandatory purchases or sales of energy into PJM's market, the Stipulation provides that PJM and the other parties are obligated not to contest AEP's decision to not participate in any such mandatory market.

deficiencies elsewhere on the PJM system so long as AEP has maintained adequate capacity in accordance with PJM's reserve methodology.

In the event of a transmission emergency, PJM is responsible only for determining the location, quantity, and timing of any curtailment. PJM is not responsible for determining or directing the manner in which load is to be curtailed during an emergency. Pursuant to Paragraph 3b of the Stipulation, PJM will direct AEP to curtail retail load only after PJM has exercised all other available opportunities to remedy an emergency without curtailing retail load.[8] Finally, the Stipulation provides in Paragraph 3d that the approval of Kentucky Power's membership in PJM will not alter this Commission's existing authority over the application by Kentucky Power of curtailment practices to its retail customers.

Based on the Stipulation's provisions on curtailment, it appears that PJM will not be in violation of KRS 278.214 since it will not be determining or directing which customers should be curtailed during an emergency. Rather, that task will remain with Kentucky Power. Consequently, approving the proposed transfer of control will have no impact on the enforceability of KRS 278.214, which is now pending judicial review.[9]

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[8] In order to ensure reliability, the Stipulation appropriately recognizes the need to be able to utilize curtailment in extraordinary circumstances such as where load shedding would be beneficial to preventing separation from the Eastern Interconnection, preventing voltage collapse or in order to restore system frequency following a system collapse. Stipulation, Paragraph 3. These extraordinary remedies are appropriately recognized and are consistent with the requirements of the North American Electric Reliability Council and the East Central Area Reliability Council.

[9] See *Kentucky Power Co. d/b/a American Electric Power v. Martin J. Huelsmann, et al.*, Civil Action No. 03-47JMH (E.D. Ky. filed July 18, 2003) and *Kentucky Power Co. d/b/a American Electric Power v. Public Service Comm'n of Kentucky*, Civil Action No. 03-CI-901 (Franklin Circuit Court, Ky. filed July 22, 2003).

The Commission had also expressed concern in the July 17, 2003 Order that Kentucky Power could be required to pay twice for adequate generating reserves: once through its owned and purchased generation, and again through PJM tariff charges.[10] The Stipulation clarifies this issue by making clear that, so long as AEP-East maintains adequate capacity in accordance with applicable PJM capacity requirements, AEP-East and the retail customers provided generation service by AEP-East will not be obligated to pay PJM to maintain adequate capacity within the PJM footprint.[11] In addition, the parties have attached to the Stipulation the detailed methodology used by PJM to determine an adequate reserve margin. The Commission is familiar with that methodology and finds that it is reasonable for use on the PJM system.

Another major concern expressed in the July 17, 2003 Order was that approving the transfer of control of Kentucky Power's transmission assets to PJM could erode this Commission's existing authority to protect Kentucky retail customers. The Commission notes that Paragraph 4 of the Stipulation is consistent with existing state authority and preserves our right, pursuant to KRS 278.285, to review any demand-side management programs that may be offered by PJM to Kentucky Power. No such program will be offered directly by PJM to Kentucky retail customers.

Finally, Paragraph 5 of the Stipulation provides that this Commission shall continue to establish Kentucky Power's rates based upon its assets included in retail rate base. This will also preserve our authority under 807 KAR 5:058 to review Kentucky Power's Integrated Resource Plan as we have done historically. Furthermore,

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[10] Order at 15.

[11] Stipulation, Paragraph 2.

the Stipulation makes clear that nothing therein, or the Commission's approval thereof, shall be construed to alter the jurisdictional authority of the Commission.

In conclusion, the Commission finds that, subject to the terms of the Stipulation, Kentucky Power's application to transfer functional control of its transmission assets to PJM is for a proper purpose and is consistent with the public interest pursuant to KRS 278.218(2), and should, therefore, be approved. This approval is strictly subject to the express terms of the Stipulation, and is contingent upon the approval by FERC of a Unilateral Offer of Settlement based upon this Order (and the attached Stipulation) in full settlement of Case No. ER03-262-009 as applied to the Commonwealth of Kentucky. The parties to the Stipulation are directed to prepare the necessary documents for this Commission's joinder in the submittal to FERC as part of this approval process.

IT IS THEREFORE ORDERED that:

1. Kentucky Power is granted conditional authority to transfer functional control of its transmission assets to PJM subject to the FERC accepting, without additions or modifications, an offer of full settlement, consisting of this Order and the attached Stipulation, as applied to the Commonwealth of Kentucky in FERC Docket No. ER03-262-009 (and related sub-dockets).

2. The parties to this case shall prepare the necessary documents for the Commission's joinder in the filing of this Order and attached Stipulation as a full settlement as applied to the Commonwealth of Kentucky in FERC Docket No. ER03-262-009 (and related sub-dockets).

3. In the event that this Order and attached Stipulation are accepted without additions or modifications by FERC as a full settlement as applied to the Commonwealth of Kentucky in Docket No. ER03-262-009 (and related sub-dockets), the conditional approval granted herein shall be unconditional, and this case shall be closed, upon the filing of a FERC order accepting the full settlement.

4. In the event that this Order and attached Stipulation are not accepted without additions or modifications by FERC as a full settlement as applied to the Commonwealth of Kentucky in Docket No. ER03-262-009 (and related sub-dockets), the conditional approval granted herein shall be null and void and further proceedings shall then be scheduled to determine whether Kentucky Power's pending application is in compliance with KRS 278.218.

Done at Frankfort, Kentucky, this 19th day of May, 2004.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2002-00475 DATED May 19, 2004.

RECEIVED

APR 1 9 2004

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218	)	CASE NO. 2002-00475

AGREED STIPULATION

The undersigned parties (parties), by counsel, hereby advise the Kentucky Public Service Commission ("Commission" or "KPSC") that the parties have agreed by written stipulation as follows:

WHEREAS, on December 19, 2002 Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") filed an application, pursuant to KRS 278.218 requesting approval to transfer control of certain transmission facilities to PJM Interconnection L.L.C. ("PJM"); and

WHEREAS, this Commission held an evidentiary hearing on said application on March 25, 2003; and

WHEREAS, on July 17, 2003 this Commission issued an Order denying the requested transfer; and

WHEREAS, in response to rehearing applications filed by Kentucky Power and PJM, the Commission granted rehearing on August 25, 2003 in order to obtain a Kentucky Power cost/benefit study and for the parties to provide additional testimony on issues raised in the rehearing applications of Kentucky Power and PJM concerning certain of the findings made by this Commission in its July 17, 2003 Order; and

WHEREAS, Kentucky Power filed a cost/benefit study in accordance with the Commission's Order on December 23, 2003; and

WHEREAS, on November 25, 2003 the Federal Energy Regulatory Commission ("FERC") in Docket No. ER03-262-009 made certain preliminary findings concerning the actions of this Commission related to the Kentucky Power application and ordered an evidentiary hearing concerning such findings; and

WHEREAS, following an evidentiary hearing, on March 12, 2004, a FERC Administrative Law Judge issued an Initial Decision confirming the FERC's preliminary findings; and

WHEREAS, continued litigation involving Docket No. ER03-262-09 before the FERC and this proceeding could be lengthy and costly; and

WHEREAS, as a matter of state law the Commonwealth of Kentucky has an industry structure of vertically integrated electric utilities serving retail customers through the provision of bundled retail electric service;

NOW THEREFORE, the parties hereby agree, stipulate and recommend to the Commission that it issue an Order approving Kentucky Power's application submitted to the Commission on December 19, 2002 to transfer functional control of its transmission facilities to PJM subject to the following terms and conditions:

1. The parties agree and stipulate that this approval is premised on PJM's operation of markets that are designed such that AEP Service Corporation's (AEP) purchases of capacity and energy, and sales of capacity and energy to, the PJM Capacity Credit Market and PJM Interchange Energy Market on behalf of its operating companies are voluntary.[1] AEP's cost of service to retail customers is subject to appropriate Commission review through rate proceedings. The parties agree to resist any proposal to mandate PJM member participation in PJM's Capacity Credit Market or Interchange Energy Market to effect sales or purchases of capacity or energy. In addition, the parties will not contest if AEP seeks not to participate in any other mandatory purchases or sales of capacity or energy in the PJM Capacity Credit Market or PJM Interchange Energy Market that FERC may subsequently propose. Nothing in this Stipulation is intended to address whatever authority FERC

[1] As to meeting capacity obligations, the PJM Interchange Energy Market is the vehicle wherein AEP is required to specify the availability of its capacity resources solely in order to ensure that PJM can call upon such capacity in the event of a generation capacity deficiency emergency. AEP has the option to meet its capacity offer obligations as well as its other obligations to serve its native load through self-scheduling. "Self-scheduling" means the designation by a utility of its own resources to meet its load obligations.

may have with respect to remedies for anticompetitive behavior or the position of the parties concerning same.

2. PJM agrees to provide information as necessary and to provide due consideration to the findings of this Commission and other Commissions within its footprint for PJM to determine the appropriate reserve margin necessary to maintain safe and reliable service. Nothing stipulated in this agreement shall supercede PJM's obligation to ensure an adequate reserve margin consistent with maintaining an acceptable level of reliability. This level of reliability shall be maintained consistent with applicable reliability principles and standards.[2] Integrating AEP into PJM will provide a larger base of generation in the PJM footprint. As a result, PJM anticipates that the integration of AEP into PJM should result over time in lower reserve margins than AEP would otherwise be required to maintain, all other things remaining equal. So long as AEP maintains adequate capacity in accordance with applicable PJM capacity requirements, AEP and retail customers provided generation service by AEP will not be obligated to pay PJM to maintain adequate capacity within the PJM footprint.

3. PJM agrees to implement curtailment protocols as follows:

   a. PJM will not direct AEP to curtail the retail customers of any AEP operating company including Kentucky Power for capacity deficiencies elsewhere on the PJM system so long as AEP has maintained adequate capacity in accordance with applicable requirements;
   b. PJM will not direct AEP to curtail retail load in any AEP-specific state jurisdiction, including Kentucky, for a transmission system emergency unless PJM has exercised all other available opportunities to remedy the emergency without curtailing such retail load;
   c. The foregoing curtailment protocols shall apply except in extraordinary circumstances such as where load shedding would be beneficial to preventing separation from the Eastern Interconnection, preventing voltage collapse, or in order to restore system frequency following a system collapse.
   d. Nothing in the approval of this application shall alter this Commission's authority over the application by Kentucky Power of curtailment practices to its retail customers.

4. Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail

[2] PJM's methodology for determining such reserve margin is set forth in Attachment A.

customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. Kentucky Power may, at its election, offer demand side response programs to its retail customers. Any such programs would be subject to the applicable rules of the Commission and Kentucky law.

5. Nothing in this Stipulation shall be construed to alter the jurisdictional authority of the KPSC or the FERC or the parties' respective positions concerning same. Should the Commission approve this Stipulation, such approval shall not be construed as approval of the removal of Kentucky Power assets from rate base and the authority to determine revenue requirements for such assets. The KPSC shall retain its existing jurisdiction to, and shall continue to, establish retail electric rates for Kentucky Power based upon its assets included in retail rate base. Nothing in this Stipulation shall preclude Kentucky Power from taking any legal position in any rate proceeding or judicial review thereof with respect to the KPSC's jurisdiction.

6. Nothing in this Stipulation or the Commission's approval thereof shall be deemed to alter in any way the existing obligation of Kentucky Power Company under the laws of the Commonwealth of Kentucky to seek a certificate of public convenience and necessity prior to commencing to construct an electric generation facility or transmission facilities.

7, Nothing in this Stipulation alters in any way the laws of the Commonwealth or rules or policies of this Commission which provide that service to retail customers be provided through the provision of bundled retail electric service.

8. The parties hereby stipulate that the Commission may rely upon the testimony submitted in this proceeding in support of this Stipulation.

9. The parties will endeavor to obtain prompt approval of this Stipulation by the Commission, no more than thirty (30) days from the date of its submission.

10. Upon approval of this Stipulation by the Commission, the parties recommend that the Commission file this Stipulation with the Federal Energy Regulatory Commission as an offer of full settlement of Docket No. ER03-262-009, as applied to the Commonwealth of Kentucky. In the event that this Commission or the FERC does not accept this Stipulation in its entirety and the FERC does not accept this Commission's Offer of Full Settlement

based on this Stipulation and the Commission's Order adopting it as applied to the Commonwealth of Kentucky, then each of the signing parties and the KPSC shall retain the right to terminate this Stipulation. In the event of such action by this Commission or the FERC, within five (5) business days any undersigned party may give notice exercising its right to terminate this Stipulation, provided that the undersigned parties may by unanimous consent, elect to modify it to meet the issues raised by the Commission or the FERC. Should any undersigned party choose to terminate this Agreement, in such eventuality, the agreement shall be considered void and have no binding precedential effect, and the parties reserve their rights to fully participate in all relevant proceedings notwithstanding their agreement to the terms of this Stipulation.

Dated this 19th day of April, 2004.

HAVE SEEN AND AGREED:

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ATTACHMENT A

PJM Generation Adequacy Analysis:

Technical Methods

Capacity Adequacy Planning Department

PJM Interconnection, L.L.C.

October 2003

Introduction

Reliability requirements for a bulk power system are typically separated into two distinct, but related, functional areas: Adequacy and Security. As defined by NERC, adequacy refers to "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[1] Security, as defined by NERC, refers to "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[1] A well planned and adequate power system will lead to a secure system in day to day operations.

Generation adequacy, or the sufficiency of generation supply to meet expected demand, is one of the fundamental components of electric system adequacy assessment. This paper examines the analytical methods and models that PJM uses to assess the generation adequacy of the region. These techniques are based on sound, proven engineering theory and the physics of the bulk electric power grid. These methods, originally developed in the 1960s, have served PJM well over the ensuing decades in providing a safe and reliable electric system.

The generation adequacy standard PJM is obligated to meet is defined in Section 1 of the MAAC Reliability Principles and Standards[2], which states:

> "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effects of connections to other pools, and network transfer capabilities within the MAAC systems."

This "one day in ten year" loss-of-load expectation (LOLE) is the standard observed in most NERC regions and is the basis for determining PJM's required Installed Reserve Margin (IRM). The probabilistic nature of this standard requires that the tools used to determine the required IRM also be probabilistic. The tool developed and used by PJM for this purpose essentially uses a convolution of expected load distributions with expected capacity availability distributions to determine the loss-of-load probability (LOLP) of the PJM system.[3,4] The model includes all factors listed in the MAAC Section 1 criteria stated above. The specific statistical techniques used by the model include:

1 Probability Density Functions
2 Convolution Functions
3 Markov equations of a four-state model [7]
4 The Central Limit Theorem

5 Monte Carlo sampling
6 The First Order Statistic
7 Correlation and regression techniques and residuals
8 Testing for normality of probability distributions
9 Confidence interval determination.

In addition to determining the required PJM Installed Reserve Margin, PJM performs a number of other related analyses including evaluation of the reliability value of load management programs, capacity emergency transfer objective studies, winter weekly reserve target studies, and peak period planned maintenance assessments (see Citations 28, 29, 30). These planning study results are often directly applied in system operations. For example, the determination of the winter weekly reserve target is applied in the succeeding winter period by Operations to ensure that planned outages are coordinated to minimize system risk and maintain compliance with the MAAC Section 1 criteria.

The main section of this paper explains why and how PJM's modeling and analysis techniques are used to assess generation adequacy from a planning perspective. It also includes the results of benchmarking analysis performed to assess the consistency of our planning model with operational experience. The main section also underscores the integrated nature of planning and operations functions at PJM by outlining the direct impacts of each function on the other.

The main section of the paper is followed by a list of references which provide the conceptual basis for PJM adequacy tools and methods. Also included is a glossary which defines the terms and acronyms used throughout the paper. The Citations and References cited at the end of this paper provide the pertinent technical details and further explanations of the concepts and techniques presented in the main section. This paper itself is a summary of numerous reports and documents that describe the techniques in greater detail and are available at the PJM Interconnection Office.

Section 1

Reserve Requirement Analysis

The primary purpose of the Reserve Requirement Study is to determine the Installed Reserve Margin (IRM) required by PJM to meet the MAAC "1 in 10" LOLE standard. While the requirement is based on MAAC criteria, it is applied uniformly across the entire PJM region regardless of NERC reliability council boundaries. The Reserve Requirement Study is performed annually by Capacity Adequacy Department staff at PJM with extensive stakeholder review through the PJM Committee structure. The IRM ultimately recommended by the Committees and approved by the PJM Board is based on consideration of the analytical results and application of engineering judgment to reflect the influence of factors not explicitly considered in the analysis.

PRISM (Probabilistic Reliability Index Study Model) is the computer application used by PJM to calculate reliability indices to determine installed capacity reserve requirements. PRISM is a Web-based software tool that was recently developed based on the GEBGE model. GEBGE is a legacy FORTRAN program that had been used by PJM for adequacy studies since the mid 1960's.

The Reserve Requirement Study is based on a data model that has five principal components:

1) 52 weekly mean peak loads
2) 52 weekly standard deviations of the loads reflecting both forecasting error and weather variability
3) 52 weekly mean generating capacity values
4) 52 weekly available capacity distributions based on characteristics of the generators (forced outage rates, planned outage requirements, etc.)
5) A deterministic Capacity Benefit Margin (CBM) value between PJM and the external regions

The external regions included in the model (collectively referred to as the "world") include ECAR, SERC, NPCC, MAIN, SPP, and MAPP. Studies can be performed on a single area (PJM only) basis or on a two-area basis (PJM and adjacent regions). The determination of reserve requirements is done on a two-area basis to recognize the reliability value of interconnection with external regions. The data model for both the load and capacity representations is based on physical, geographic location.

The Reserve Requirement Study also produces the Forecast Pool Requirement (FPR) which is the IRM converted to units of unforced capacity. Unforced capacity (UCAP) represents the expected megawatt output of a unit that is, on average, not experiencing a forced outage. UCAP is used to assign capacity obligations and to measure compliance with those obligations. UCAP is also the units on which the PJM capacity markets are based.

The Reserve Requirement Study assesses the adequacy needs of the pool for each of the next five years. Results are primarily influenced by the characteristics of the generating units, variability of load, expected amount of new generation, load forecast error, and available capacity assistance from adjacent regions. The IRM is officially approved on a one year-ahead basis. Once approved, the IRM is held constant for the duration of a full planning period (June 1 through May 31 of the following year).

Two Area Model

The Reserve Requirement Study models two separate areas: Area 1 is the study region (PJM) and Area 2 is the electrically significant region connected to PJM (the "world"). As a result, the bulk electric power grid of most of the Eastern Interconnection is modeled. Geographically, this area includes most of the U.S. and Canada between the Atlantic Ocean and the Rocky Mountains. The bulk electric power grid generally includes all elements connected to the 138 kV and higher voltage level system.

The Reserve Study model includes three primary components: load, capacity, and the transmission link that connects PJM with the world area. The value of the simultaneous capability of the transmission link, under peak load conditions, is known as the Capacity Benefit Margin (CBM).[13, 14] The load and capacity models are probabilistically based, whereas the transmission link is represented by a single, expected value. As detailed in the Capacity Benefit Margin section of this paper, the determination of the expected transmission link is based on a probabilistic weighting of results from a series of power flow simulations.[15] A geographical representation of the Reserve Requirement Study model is shown in Diagram 1. A conceptual representation showing the three primary modeling components is depicted in Diagram 2.

Diagram 1

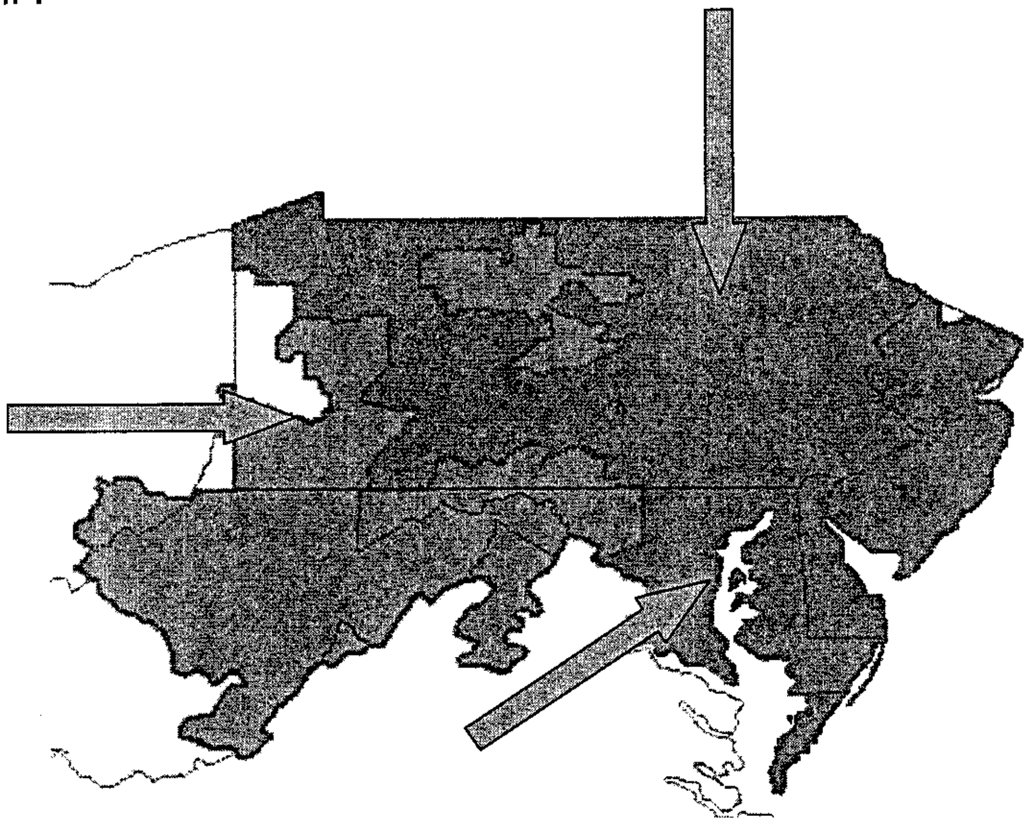
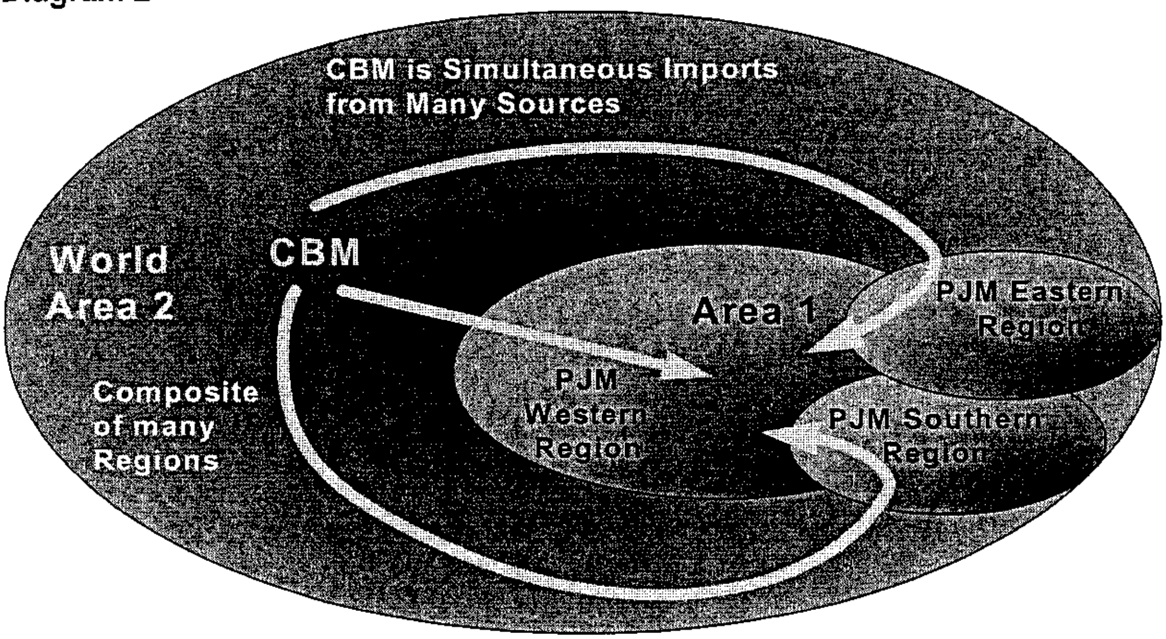


Diagram 2



PJM Region

Data for the PJM Region model is supplied by stakeholders (primarily Generators and the Electric Distribution Companies) and is also collected from PJM data systems. Stakeholder data is thoroughly reviewed by PJM staff to ensure accuracy. Three cases are currently developed for the Reserve Requirement Study to represent the three possible PJM configurations:

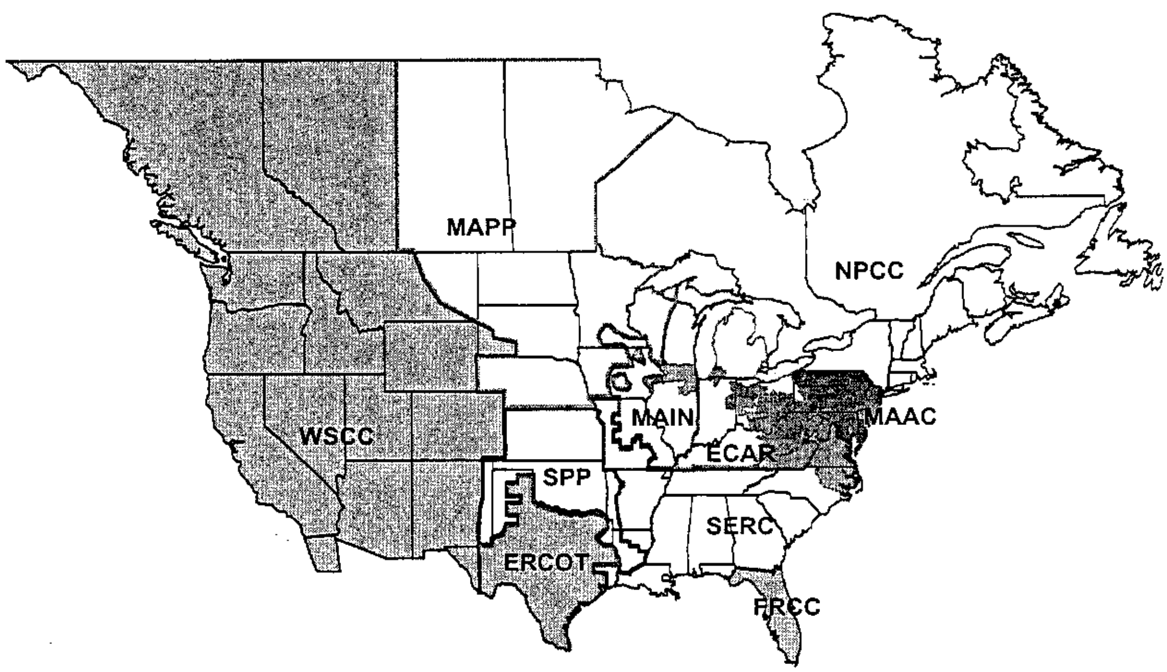
1) the MAAC region only
2) the MAAC region plus Allegheny Power
3) the MAAC region plus Allegheny Power, Commonwealth Edison, AEP, Dayton Power & Light and Dominion Virginia Power

These regions comprise the green/bluish-green area depicted in Diagram 3.

World Region (Eastern Interconnection minus PJM, ERCOT, and FRCC)

The world region is the area electrically interconnected to the PJM region. Diagram 3 shows this as the area in white. Regions in Texas, Florida, and west of the Rocky Mountains are not strongly interconnected to PJM and therefore are not modeled in the study. Diagram 3 shows the areas not modeled in the study in yellow.

Diagram 3



Single Transmission Tie (CBM = 3500 MW)

The model includes a single, bi-directional transmission tie between the two study regions. This tie represents the transmission system's ability to deliver capacity resources into PJM under peak demand periods. Power flow studies using Monte Carlo generator outage techniques[15] indicate that this value is 3500 MW. The 3500 MW emergency import capability is defined to be the Capacity Benefit Margin and is reserved for adequacy purposes and is therefore not available for firm transmission service under non-emergency conditions. Preserving this CBM for reliability purposes effectively reduces the calculated IRM by two to three percentage points. This collective benefit is shared pro-rata by all load serving entities in the PJM region.

Recent studies [22, 23] of the expanded PJM region indicate that PJM's emergency import capability (EIC) now exceeds 3500 MW. Statistical studies [17, 18, 19, 20], however, indicate that the vast majority of the reliability benefit of interconnection is supplied by the first 3500 MW of import capability. For this reason, CBM has been effectively capped at 3500 MW. Reserving import capability in excess of 3500 MW provides a minimal amount of additional benefit. Any EIC in excess of 3500 MW is therefore not reserved for reliability purposes and can be used to increase the amount of firm Available Transmission Capability available to the marketplace.

PRISM - Probabilistic Reliability Index Study Model

The models and analytical techniques used for generation assessment are based on numerous technical papers [5, 6, 11, 12] and on the physical nature of how generating machines, peak demand period loads and the transmission system interact in the delivery of energy across the bulk power grid. PJM has successfully used these techniques for more than 35 years in determining pool wide reserve requirements.

The PRISM (Probabilistic Reliability Index Study Model) tool uses SAS [24] software as an analytic engine and Oracle [25] as a database to enhance the PJM staff's abilities to assess adequacy requirements. The tool's focus is on creating a probabilistic generation model and load model and convolving the two to determine the probability of load exceeding available capacity. The generation and load models are based on the latest available information which offers the best predictor of future adequacy requirements.

PRISM analyses a weekly distribution of the expected peak loads and a distribution of the expected available capacity level in each study area. Each weekly load distribution is modeled to be normal (i.e. Gaussian). These distributions are based on the load data for the previous five years and the five year average generator availability statistics respectively. These two distributions are then convolved as depicted in Diagram 4. Two weeks are depicted in this diagram: one pertaining to a high demand peak week and the other to a low demand, non-summer week.

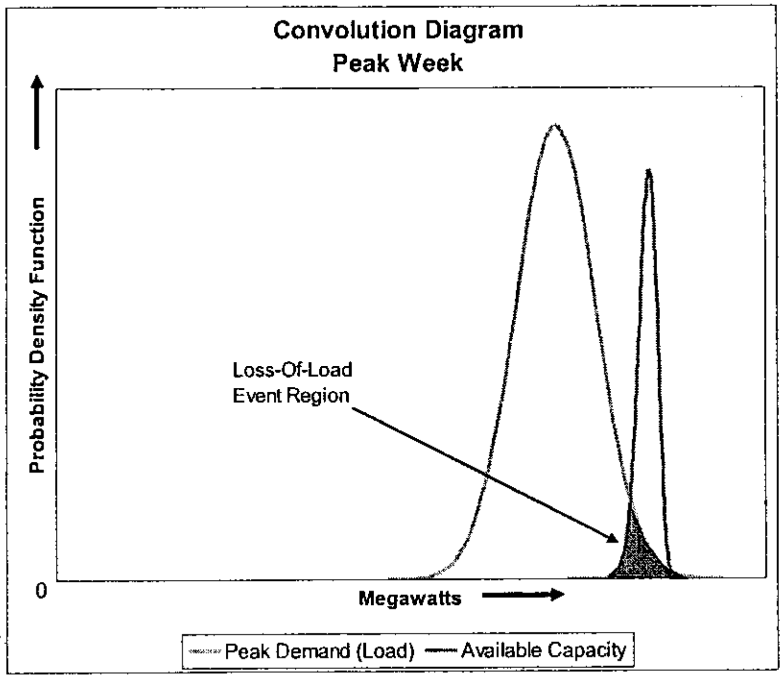
As depicted in Diagram 4, if load exceeds available capacity (the green line is to the right of the blue line), demand is unable to be served and a loss of load event occurs. The probability of a loss of load event occurring in that particular week is simply the area under the curves and shaded in red on the diagrams. The loss of load probability is therefore a joint probability calculation – the load level must be at a certain

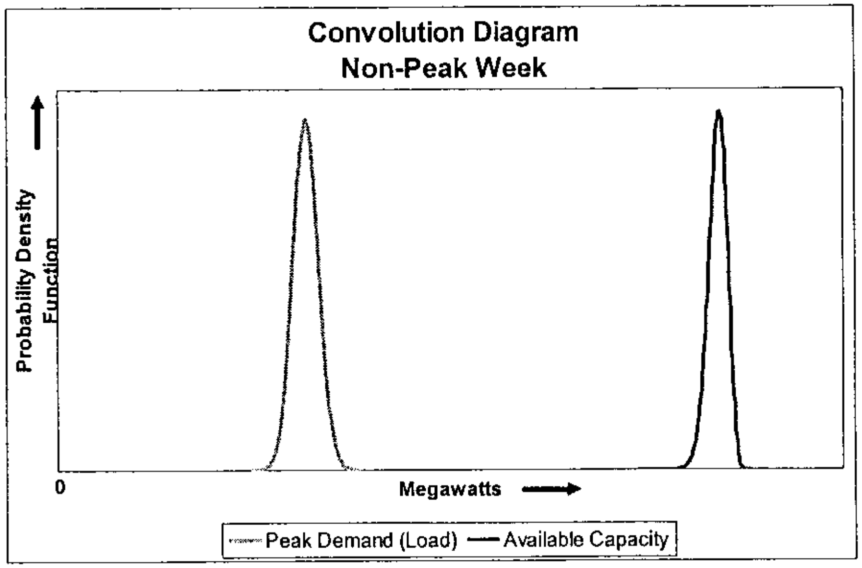
MW value coincidently with the available capacity level being below that same MW value. It is important to note that this model assumes independence between the load distribution and the capacity distribution.

Diagram 4 clearly shows that the loss of load probability (LOLP) is much greater on a peak week than on a non-peak week. This is due primarily to the load distribution, which has a higher mean and higher standard deviation during the peak week. This increases the potential for overlap (or red shaded area) between the two curves. Note the standard deviation of the capacity distribution is relatively small. This is due to the large number of units within PJM. With over 700 units, the possible range of system unit average unavailability decreases significantly and clusters around the mean. **This tight standard deviation on the capacity distribution applies to both peak and non-peak weeks and serves to reduce the loss of load probability.**

PRISM performs the convolution calculation for each week of the year and for each area of the model. The weekly LOLPs are then summed to determine the seasonal LOLPs, which are summed to produce the annual LOLP. The annual LOLP is the value that must meet the MAAC standard of a "1 in 10" loss of load expectation.

Diagram 4





The details of the model development are described below.

Load Model

The general shape of the load distribution is based on metered control area loads over a five year period. Hourly loads from each year are normalized based on the respective annual peaks to remove the effects of load growth. Basing the shape on five years of history is judged to be the appropriate period that both balances having a sufficient number of data points to reduce volatility and ensuring the model reflects recent load characteristics.

The load model used in the Reserve Requirement Study is "magnitude-ordered". This means that the weekly load data is not considered in chronological order but is ordered instead within each season of each year from the highest to the lowest. The loads are then averaged across the five year period based on this magnitude ordering (i.e. the highest weekly loads are combined across the years, the second highest weekly loads are combined and so forth through 52 weeks). The 25 points collected for each week (the 5 weekday peaks from each of the 5 years) then define the mean and standard deviation of the load distribution for that particular week. This "magnitude-ordered" approach results in an annual load profile that benchmarks very well with actual load experience. A load model approach that simply combined loads across years based on "calendar-ordering" (i.e. the first week of each June combined, the second week of each June combined, etc.) would tend to flatten out the load shape and result in an anomalous load profile that does not resemble any annual profile observed in operations.

Diagram 5 shows the distribution of daily peaks occurring on the five weekdays of a particular week. This normal distribution is characterized by its mean and standard deviation and is assumed to be identical for each of the five weekdays within a particular week. [26] PRISM develops 52 of these distributions, one associated with each week of the planning period. The value of the most probable weekly peak is determined from this curve based on use of the First Order Statistic. The First Order Statistic [27] empirically predicts the expected highest observation within a sample of a fixed size, where the population mean and standard deviation are known. For the most probable peak (MPP) calculations, the population is defined by the weekly load distribution and the sample size is five (one for each weekday of the week). From the First Order Statistic table [27], this sample size yields a First Order statistic of 1.16295 and is inputted into the formula below:

$$MPP = \mu + 1.16295\sigma$$

This formula states that, if 5 data points are randomly sampled from the distribution on Diagram 5, the expected value of the highest of the 5 data points (corresponding to the weekly peak) would be 1.16295 standard deviations above the distribution mean. The expected weekly peaks (or most probable peaks (MPPs)) across an entire planning period are plotted on the y axis in Diagram 6 (red line).

Another input to the load model is the historical load growth rate and the monthly peak demand forecast. The load shape is adjusted to essentially replace the historical load growth reflected in the metered loads with the current forecasted load growth for the future study period. Historical load growth is removed by normalizing loads based on the respective annual peaks. This adjustment ensures that the resulting load model is a more accurate predictor of future adequacy requirements.

The load model also recognizes the increased forecast uncertainty associated with longer planning horizons. This is accomplished through application of a unified increase in error for each week based on the length of the planning horizon under study. The increase in error is referred to as the Forecast Error Factor (FEF) [31]. The FEF adjustment is made each week according to the formula:

$$MPP = \mu + 1.16295\sigma_{\text{Total}} \text{ ,}$$

where:

$$\sigma_{\text{Total}} = \sqrt{\sigma^2 + FEF^2} \text{ .}$$

Thus the FEF adjustment has the effect of increasing the weekly load distribution standard deviations associated with planning periods further out in the future. The Reserve Requirement Study load models typically use an FEF of 0.5% error in the first planning period and increase this value by 0.5% for each succeeding planning period of the study. [17, 18, 19, 21, 31] The maximum FEF value is a 3% error and occurs six years forward in time.

The distribution of daily peaks within a week is assumed to be normal. [10] Analysis of historical daily peaks for each week of the year supports this assumption. [26] Historical data for sixty percent of the weeks are strictly normally distributed. Those weeks that are not strictly normally distributed have distributions that are bell shaped but exhibit some skewness. In particular the summer (peak) weeks show some negative skewness (i.e. the median daily peak is greater than the mean daily peak).

Using a normal distribution to represent these weeks is a conservative assumption, since it aligns the mean and median daily peaks and shifts the distribution to the right increasing the likelihood of exceeding the available capacity. Please refer to the Citations, primarily numbers 10 and 26, for a detailed description of the data and statistical testing and verification performed to demonstrate that a normal distribution for each week's daily peaks is appropriate.

Diagram 5

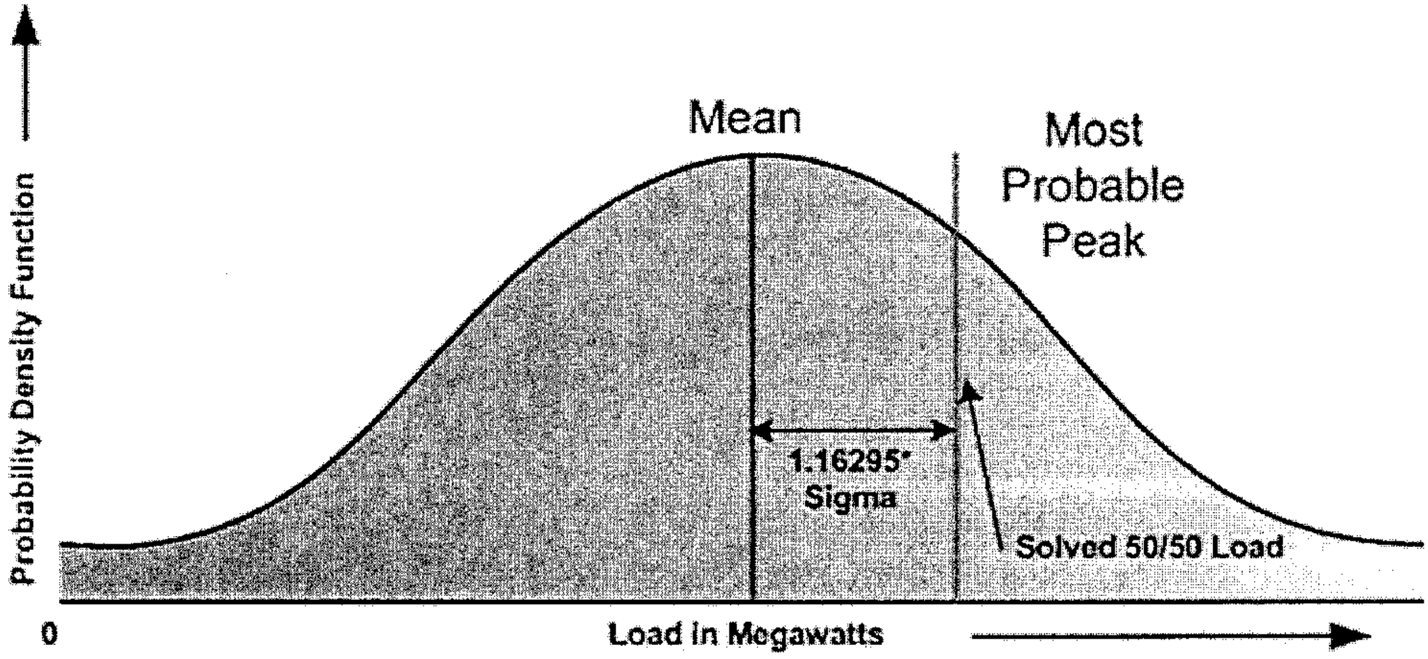


Diagram 7 emphasizes the point that each weekly load point on the annual load shape does not represent a single value, but is itself the most probable peak drawn from an entire distribution of possible peaks. A load distribution similar to the one depicted in Diagram 5 is associated with each weekly peak plotted in Diagram 6. This approach ensures that every possible load level, not just the expected or average load level, is considered in our adequacy analysis.

Diagram 6 – Load Shape

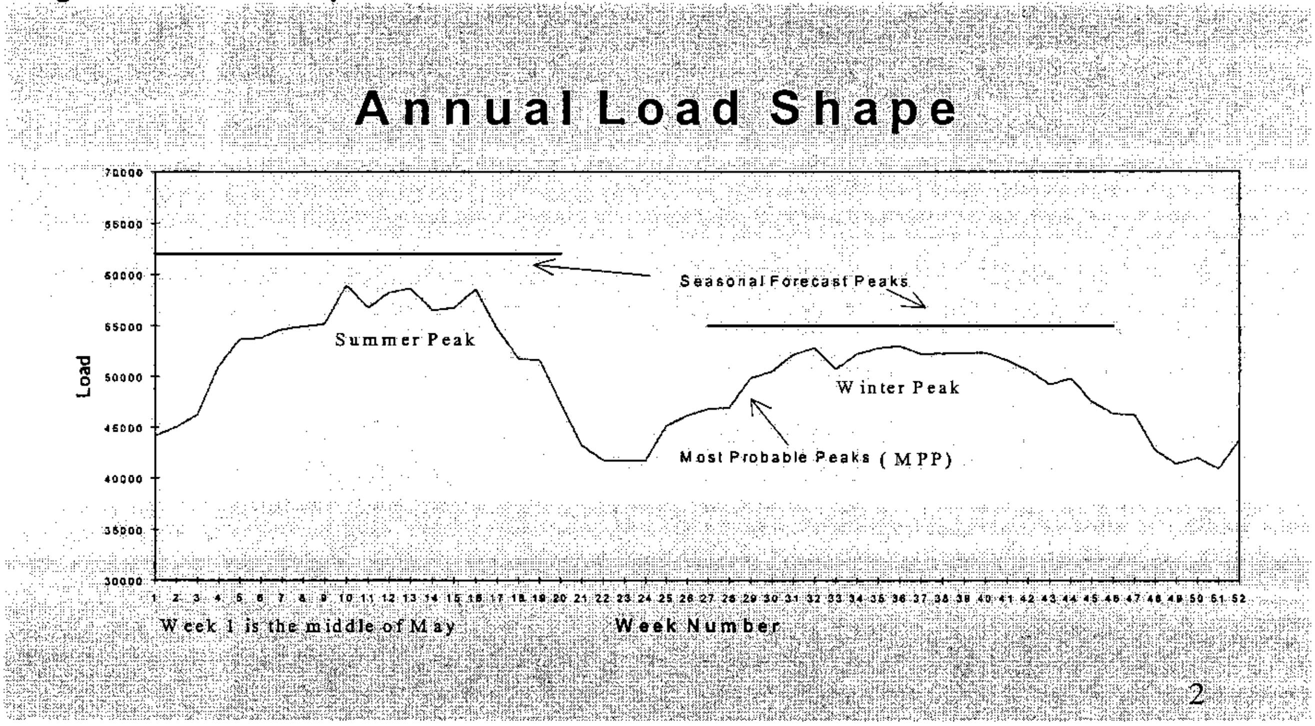
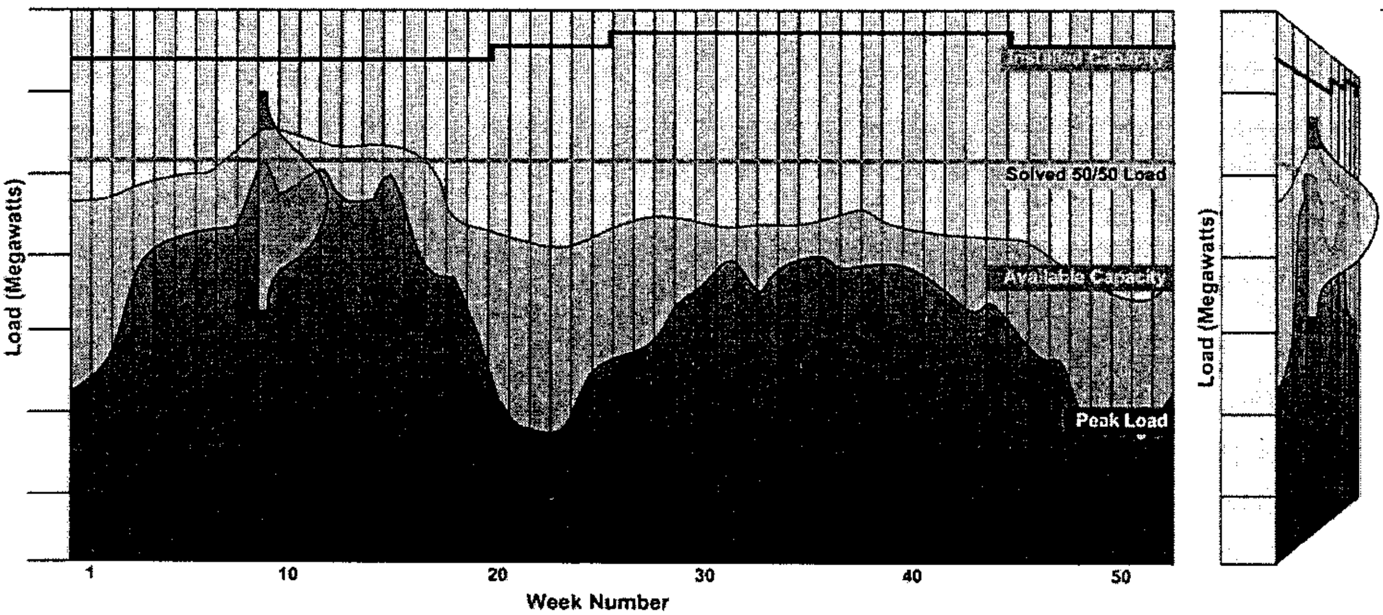


Diagram 7 – Load Shape combined with Weekly Load Distribution



The Green line represents the Available capacity. The tail of the weekly load distribution shown above the green line represents a loss-of-load event. Picture this diagram in 3 dimensions with the bell shape load extending up out of the page as shown in the image to the right.

Capacity Model

The PRISM capacity model explicitly models each generating unit in each area. The following input data is required for each unit:

1. Name
2. Location
3. Summer and Winter Capacity Ratings
4. Effective Equivalent Demand Forced Outage Rate (EEFORd)
5. Two State Variance
6. Planned Maintenance Requirements

The EEFORd statistic [7, 8, 32] is effectively the forced outage rate of the unit (which is an all-hours performance measure) adjusted to reflect the availability of the unit only over the hours during which it is "in demand" or required to produce energy. The two-state variance statistic [31, 32] is a single value which captures the effect of up to twelve partial outage states of the unit. The maintenance data specify the number of weeks per year required for planned maintenance. The calendar scheduling of that maintenance is optimized by PRISM by coordinating it with the maintenance requirements of all other units in that study area. These input statistics are fully developed in the Citations and References to this paper, primarily in Citation numbers 31 and 32.

The volume of data required to develop a capacity model for a 700 unit PJM region and a world area of over 4500 units is significant. Data warehousing technologies and SAS software [24, 25] have been developed to expedite the storage and extraction of this data. These new tools have dramatically reduced the amount of staff time required to produce the capacity models and allow sensitivity analyses to be performed in a much more efficient manner.

Generation statistics are generally based on the most recent five years of historical performance. This time period is consistent with that used for load model development and effectively balances the need for data timeliness with relative stability across years. Data reporting generally comports with Generation Availability Data Systems (GADS) standards. GADS [33] standards are established by NERC. Members submit the details of generating unit outage events through the Web-based eGADS tool [33]. PJM staff performs checks on these data and uses the Generator Outage Report Program (GORP) to produce all the statistics used in the capacity model development. The PJM Generator Unavailability Subcommittee (GUS), a stakeholder body of experts in generator performance analysis, advises PJM staff on the definitions and use of the performance statistics.

NERC compiles class average performance data for various generators based on type, fuel supply and megawatt size [34]. PJM uses this class average data for the world units and future units in the PRISM model. An in-house application makes the necessary calculations to produce the statistics needed for EEFORd, variance, and the planned outage factor used to estimate planned maintenance. New generating units roll actual performance data into their historical base as it becomes available. NERC updates the class average generator data on an annual basis.

To develop the weekly capacity distributions, PRISM first addresses the need for planned maintenance outages. Each generating unit is assigned an expected number of weeks per year to be out on a planned outage event. PRISM considers the maintenance requirements of all units in a particular area and determines for each week which units, if any, will be on a scheduled planned outage. The general goal is to schedule planned outage events in periods, such as the spring or fall, where the risk of a loss-of-load event is small. If the planned outage requirements of all units can not be accommodated in the non-peak periods, then PRISM may schedule units for maintenance during the peak periods. PRISM also allows the user to manually enter a planned outage schedule for all units if a known pattern is required for analysis. Manually specifying a planned outage pattern is typically how actual events seen in operations are modeled. Each week in the model has its own planned outages scheduled unit by unit.

An examination of operations experience [21, 35] indicates that, on average, for the MAAC region PJM has one large generating unit out over the summer peak period due to any one of several reasons (extended forced outage, Nuclear Regulatory Commission-ordered shutdown, ramp up/ramp down time, etc.). To reflect this typical level of generator unavailability over the summer period, a large generating unit is manually scheduled out over the peak period in the Reserve Requirement Study. This adjustment is a conservative assumption that results in a higher reserve requirement of about one to two percentage points. Further discussion of this topic is provided in Section 2.

Capacity Benefit Margin

The determination of the transmission system's ability to import energy from outside the PJM Control Area under peak demand periods is based on power flow analysis of the bulk electric power grid. The models are developed based on cases from the NERC Multi-area Modeling Working Group (MMWG). Each year, the MMWG produces up to nine planning models useful for analyzing power flows anywhere in the Eastern Interconnection. The nine models capture a range of operating conditions such as summer, winter, fall and spring peak periods, shoulder periods and minimum load periods. The objective of the models is to form the basis for assessment under all operating conditions. The models are developed through a collaborative process involving extensive stakeholder input and review.

PJM has a defined analytical process, the Emergency Import Capability Study (EICS) [15], that outlines the various assumptions and techniques used to determine the Capacity Benefit Margin (CBM). This study examines peak summer conditions and assesses the transmission system's ability to supply energy to the borders of the PJM Control Area simultaneously from all interconnected regions. All systems within the Eastern Interconnection are assumed to be under peak loading conditions.

In the power flow based EICS, the selection of generating unit forced outages is performed using a Monte Carlo selection routine. The forced outage rate for each unit is given as the EEFORd, with this statistic indicating a unit's random availability. This statistic is used to influence a random selection of generating unit outages for assessment of the transmission grid under peak load conditions. By employing a Monte Carlo technique to select generator outage patterns, the power flow analysis has moved toward a probabilistic approach for a large contributing aspect of the determination of transmission capability. The selection of units to be forced out plays a key role in the final determination of the emergency import capability. The current peak load emergency import capability reserved as CBM is 3500 MW. [13]

PRISM Solution Algorithm

The reliability program's capacity model uses each generating unit's capacity, forced outage rate, and planned maintenance requirements to develop a cumulative capacity outage probability table for each week of the planning period. Planned maintenance scheduling can be specified by the user or performed by the program.

Outage statistics of generating units are maintained for twelve outage states [33] (from unit "full on" to unit "full out"). PRISM cannot model these partial outages explicitly. The solution is the modified two-state variance representation for partial outages.[32] This two-state variance is used by PRISM to modify both the unit capacity and the effective forced outage rate to provide a statistically accurate representation of the 12 basic partial outage states. PRISM models a unit either full on or full off, but with the modified capacity and EEFORd the effect of the partial outages are captured. The result is a significantly better representation of the true availabilities of the generating units.

After scheduling planned outages, PRISM calculates a cumulative probability table for every week of the year based on the units in service and not on maintenance. The program then calculates the system LOLE at a given load level. PRISM calculates, on a weekly basis, the probability of every possible load level (represented by 21 intervals describing the area under a normal distribution for that interval) occurring simultaneously with every possible generation availability level (from the cumulative probability table). Any combination of load and capacity which results in the load level exceeding the generation available level contributes to the probability of a negative capacity margin (loss-of-load). In a two-area calculation, the probability that the other area will have an excess capacity margin, within the value of the tie size, is then subtracted from the first area's probability of loss of load.

The probability of zero margin or less is summed for each of the 21 intervals and then multiplied by 5 (5 weekdays per week) to give the loss-of-load expectation for that particular week. [3, 5, 6, 11, 12, 31] (Based on previous study findings, the loss of load probability over weekends and holidays is assumed to be zero.) The individual weekly LOLE's are then summed over the entire year to determine the annual LOLE. The annual PJM LOLE is currently required to be no worse than one day in ten years as mandated by MAAC. The reliability program reaches its solution by adjusting the load distribution, as opposed to attempting to outage generating capacity, until the annual LOLE is equal to one day in ten years.

A brief numerical example of the calculations is shown in the following illustration. The loss of load calculations shown in red corresponds to the red loss-of-load region shown in the above convolution diagram (Diagram 4). This example is a two-area solution that assumes the two areas will share reserves but that neither region will invoke load shedding to assist the other. This reflects the practice that PJM actually observes in operations.

ILLUSRATION OF TWO AREA Loss-Of-Load-Probability(LOLP) METHOD (NO LOSS OF LOAD SHARING)

Area A: 50 MW (5 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 30 MW load; 20 MW reserve
Area B: 60 MW (6 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 40 MW load; 20 MW reserve

Area A

A outage, MW	0	10	20	30	40	50
A probability	0.32768000	0.40960000	0.20480000	0.05120000	0.00640000	0.00032000
Help available	20	10	0	0	0	0
Help needed	0	0	0	10	20	30

Area B

B outage MW	B Proability	Help Available	Help needed						
0	0.26214400	20	0	0.08589935	0.10737418	0.05368709	[illegible]	[illegible]	0.00008389
10	0.39321600	10	0	0.12884902	0.16106127	0.08053064	[illegible]	0.00251658	0.00012583
20	0.24576000	0	0	0.08053064	0.10066330	0.05033165	0.01258291	0.00157286	0.00007864
30	0.08192000	0	10	0.02684355	0.03355443	0.01677722	[illegible]	[illegible]	[illegible]
40	0.01536000	0	20	0.00503316	0.00629146	0.00314573	[illegible]	[illegible]	[illegible]
50	0.00153600	0	30	0.00050332	0.00062915	0.00031457	[illegible]	[illegible]	[illegible]
60	0.00006400	0	40	0.00002097	0.00002621	0.00001311	[illegible]	[illegible]	[illegible]
							0.05120000	0.00640000	0.00032000

Key

1	No help needed; no loss of load	Probablity:	0.84892713
2	A gets help from B; loss of load avoided in A	Probablity:	0.03523215
3	A does not get help from B; loss of load only in A	Probablity:	0.01696072
4	B gets help from A; loss of load avoided in B	Probablity:	0.06543114
5	B does not get help from A; loss of load only in B	Probablity:	0.02772173
6	Loss of load in A & B	Probablity:	0.00572713
		TOTAL:	**1.00000000**

LOLP in A = Prob (3) + Prob. (6) = 0.02268785
LOLP in B = Prob (5) + Prob. (6) = 0.03344886
LOLP in System = Prob (3) + Prob. (5) + Prob. (6) 0.05040957

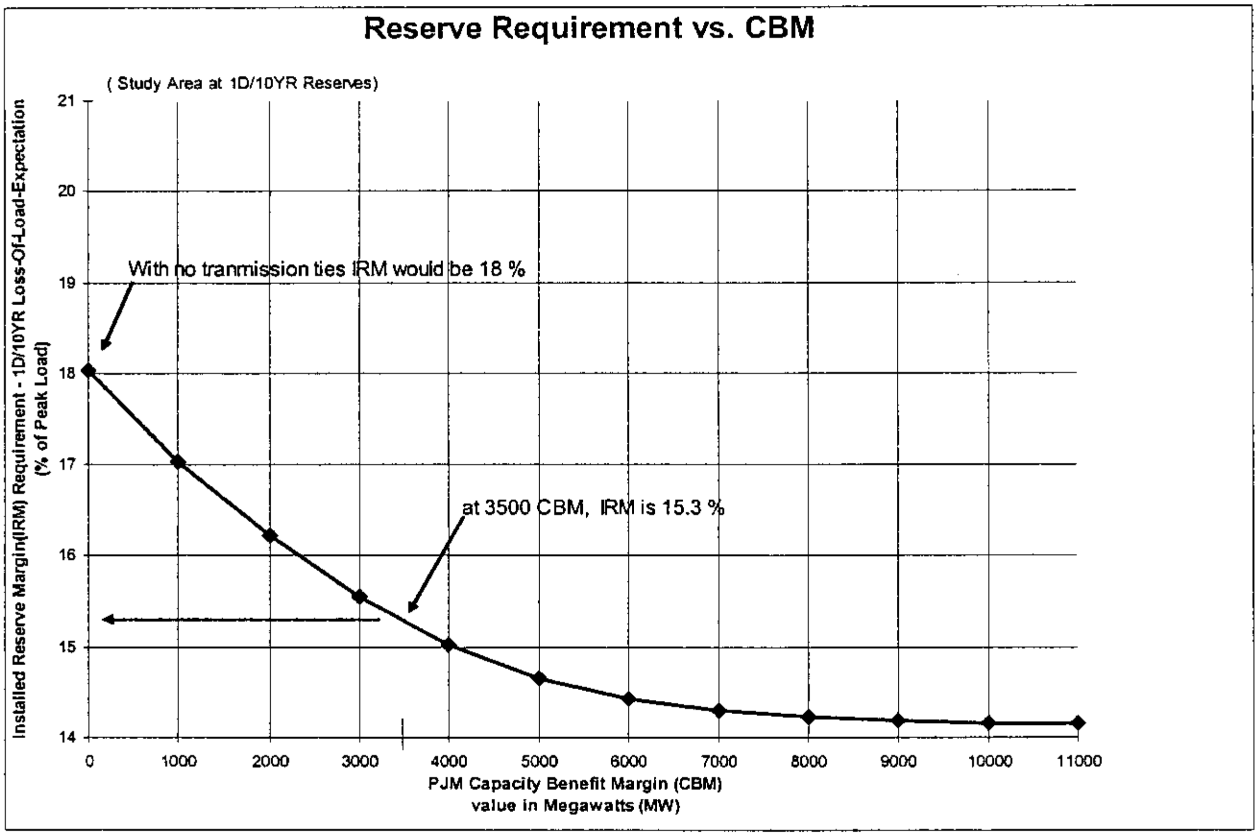
0.05792000	[illegible]	Zero Tie Size , LOLP in A
0.03523215	[illegible]	Help from B for A
0.02268785	A-B	LOLP in A with Tie

The example calculations above display the techniques used to convolve the load model needs with the generator units' availability. This exhaustive technique, known as enumerated states, [36, 37, 38, 39, 40] produces the loss of load expectation (LOLE) at a given reserve level. If that LOLE is a value other than one day in ten years, PRISM shifts the annual load shape, in aggregate up or down, performs the distribution convolution again, determines the new LOLE and continues with this iterative technique until the desired LOLE is obtained. Once an LOLE of one day in ten years is obtained, the ratio of the PJM area's installed generation to its annual peak is the calculated Installed Reserve Margin (IRM).

PRISM does not use Monte Carlo sampling because, through the use of probabilistic distributions, the calculations consider every possible load and capacity state. The program does not produce any confidence interval associated with the results because the results represent the exact loss of load expectation (based on the study assumptions), not a statistically estimated parameter. Monte Carlo techniques necessarily provide an expected result with a certain confidence level because an infinite number of simulations would be required to produce the exact result with 100% confidence.

As seen in the above calculations the advantage of being tied to neighboring systems is that they can lend assistance during times of need when an individual area needs to avoid a loss-of-load event. Critical factors in these calculations are the amount of MW assistance that are needed, the ability of the other area to have excess to help (largely driven by load diversity between PJM and the world area) and finally the ability of the transmission system, via the Capacity Benefit Margin, to deliver the excess from the other area.

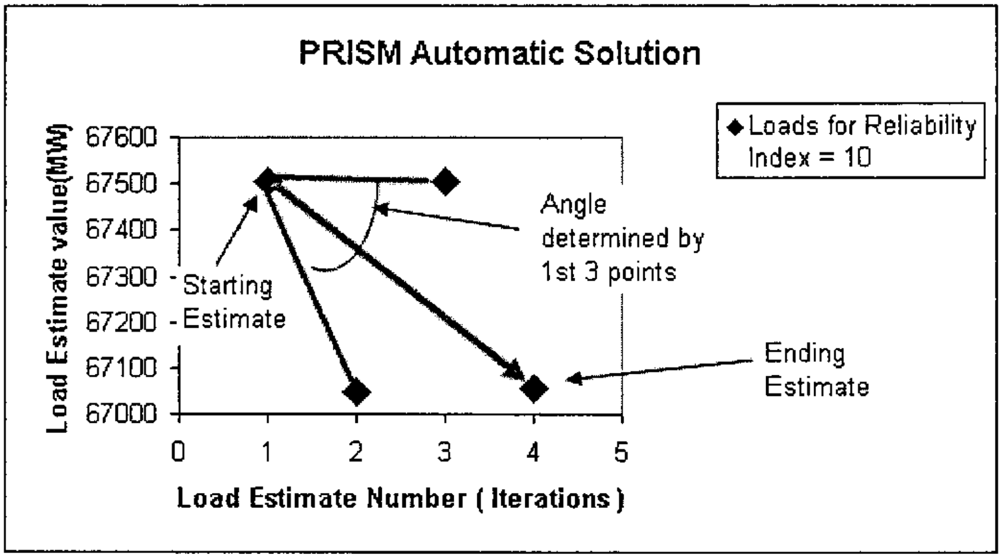
Diagram 8



The benefit of interconnection is depicted in Diagram 8. This diagram plots the PJM Installed Reserve Margin (IRM) against the Capacity Benefit Margin (CBM). As CBM increases, the potential amount of external capacity assistance increases and hence the PJM reserve requirement is reduced. As illustrated in the graph, the reliability benefit from increasing CBM reaches a saturation point around 6000 MW. At an import level of 6000 MW, the need for and availability of assistance from external regions are exhausted. The steepest portion of the curve is in the 0 MW to 3000 MW range and represents the most valuable portion of the CBM. Based on this graph and other considerations, the CBM value is fixed at 3500 MW.

A unique feature of PRISM is that a given reliability index can be set, say 1 event every 25 years, and the program will determine the solved load that meets this reliability index. PRISM does this by using an initial guess, similar to the way Newton-Raphson solutions work, and then doing a four part iteration to determine a next guess at the required load. [31] For a two-area study, PRISM uses a four part process. The initial estimate is used first, then Area 2 load is held constant while Area 1 load is varied, and then Area 1 load is held constant while Area 2 load is varied. Based on the results of the first three steps, the fourth step sets a new load for both Area 1 and Area 2. These loads are selected based on the slope of the blue lines depicted in Diagram 9. The solution process ends when either the maximum number of iterations is exceeded or the loads yield a reliability index within a specified tolerance of the desired index. This automatic solution allows PRISM to determine the required reserve margin based on a user-defined reliability index (i.e. one day in ten years).

Diagram 9



Example calculations of the automatic solution process:

RUN NO. 1 ------------------

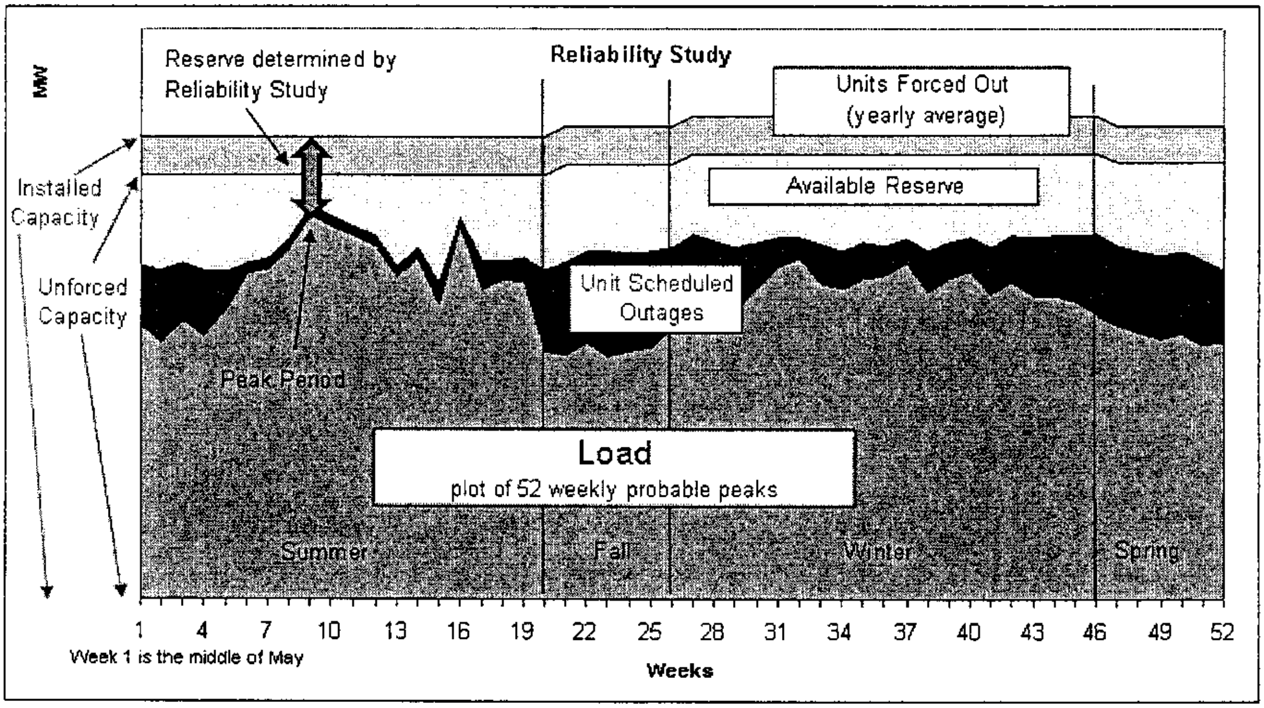
Area1 Load		Area1 RI	Area2 Load	Area2 RI-	
Part1	67504.00	8.01085	285178.00	9.59950	RI = Reliability Index (years/day)
Part2	67048.85	10.0380	285178.00	10.0089	
Part3	67504.00	8.19631	284823.62	10.1528	
Part4	67056.34	9.99760	285179.28	9.99989	

RUN NO. 2 -------------------

Area1 Load		Area1 RI	Area2 Load	Area2 RI-
Part1	67056.34	9.99760	285179.28	9.99989
Part2	67055.84	9.99791	285179.28	9.99990
Part3	67056.34	9.99760	285179.19	9.99989
Part4	67056.34	9.99760	285179.28	9.99989

Diagram 10 graphically depicts the results of the final iteration of a one day in ten year case from PRISM. The blue area represents the weekly peak demand levels, the maroon area represents the capacity on a planned outage and the light green area represents the capacity forced out. The vertical red arrow represents the installed reserves over the annual peak required to meet the desired reliability index.

Diagram 10 – Annual Load and Capacity Profile



ALM Factor Calculation

Active Load Management (ALM) [16, 41] refers to several different types of demand side programs that are implemented by PJM as one of the final steps before a loss of load event is initiated. Some examples of ALM are radio controlled activation of residential air conditioners and water heaters and contractual agreements with commercial and industrial customers to cut load upon notification. ALM does not include load curtailment achieved by promoting more efficient lighting and motors. These and other similar measures are referred to as Passive Load Management. ALM also does not include economic demand-side management programs which are voluntary, are not subject to PJM operational control, and therefore receive no capacity credit.

The reliability value of Active Load Management for Installed Capacity Accounting purposes is determined by calculating an ALM Factor using PRISM. This calculation is performed in units of load carrying capability (LCC).[9, 31] LCC refers to the amount of load, expressed in megawatts that a given resource can serve at a reliability index of one day in ten years. In this analysis, the aggregate pool ALM amount is represented as a hypothetical generating unit with a zero forced outage rate and zero planned outage events. The LCC of the aggregate ALM amount is the difference between the solved load from the base case without the "ALM generator" and the solved load from the case with the "ALM generator":

ALM LCC = Load served with ALM – Load served without ALM

The ratio of the ALM LCC to the total amount of ALM in the pool is the ALM Factor. This factor typically ranges from about 0.95 to 0.99. This number means that every 100 MW of ALM effectively reduces the load requiring reserves in PJM by 95 to 99 MW. This ALM Factor is then used in the capacity obligation setting process to reduce the obligations of those entities with ALM customers.

Two other tests are performed related to the assessment of ALM programs. The first is to verify that the full reliability value of ALM is realized in the summer period. This test justifies the granting of full year capacity credit to ALM programs that may cover only the summer period. The second test is to verify that the full reliability value of ALM is realized in ten or fewer interruptions per year. Ten interruptions is the current requirement for granting ALM capacity credit. Recent tests indicate that the reliability value of ALM saturates in the range of four to seven interruptions, well below the ten interruption requirement.[19, 21, 31] A detailed discussion of these ALM tests is included in the Citations and References, primarily citation numbers 17, 21, 31, and 41.

Committee Review and Approval

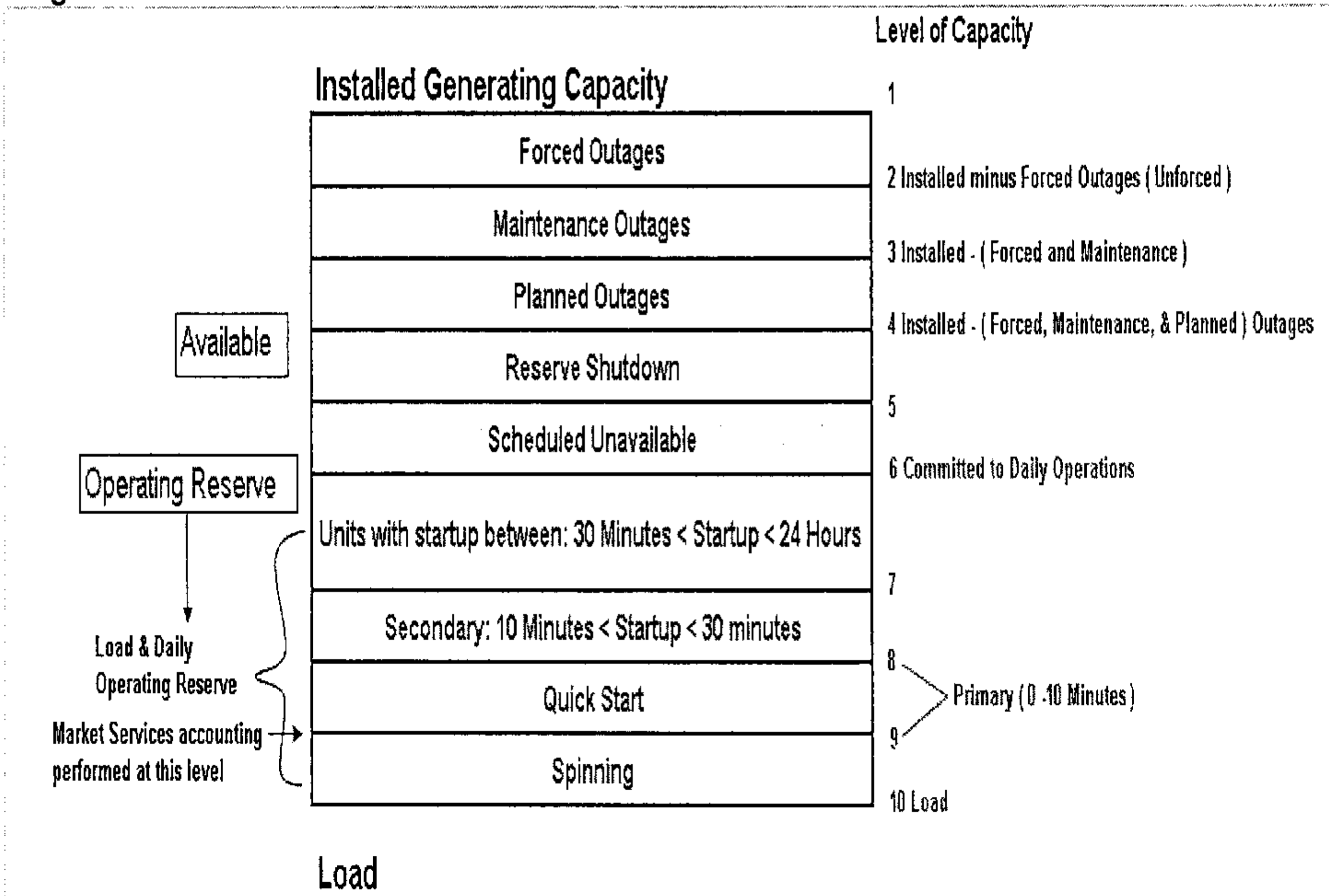
The ultimate authority over the determination of the approved Installed Reserve Margin and ALM Factor rests with the PJM Board of Managers. A supporting stakeholder committee structure is in place to advise and make recommendations to the PJM Board as necessary. Technical subcommittees, the Generator Unavailability Subcommittee and the Load Analysis Subcommittee, and PJM Staff , provide data input and begin initial review of the study results. All technical reports are passed up to the Members Planning Committee. The Planning Committee then forwards its recommendation to the Reliability Committee (RC). At the RC level, a formal vote is taken on the Installed Reserve Margin and ALM Factor and that recommendation is submitted to the PJM Board for final consideration.

Section 2

Benchmarking of Study Results with Operations

Diagram 11 shows how the same piece of generating equipment can have various values and requirements associated with it. Typically the planning processes used to measure a given unit's ability to deliver under peak load conditions are the areas shown in blue. The summer net dependable rating of a unit is the PJM Installed Capacity listed as level 1. This is the level for all adequacy analysis performed by PRISM. The PJM capacity market metric is the unforced capacity level indicated as level 2. The levels shown in red, levels 6 -9, are the typical levels at which operations measures compliance for security assessments. In all cases, each level is a measurement that is needed to assess different bulk system grid requirements. This diagram highlights the point that, while adequacy assessments and security assessments may be performed using different metrics, both consider the reliability values of generators. These values are, in fact, equal under both assessments when measured on a similar basis.

Diagram 11



All modeling techniques and assumptions for the Reserve Requirement Study are reviewed with stakeholders. Typically, the first draft of the modeling assumptions and workplan for the annual study is distributed for feedback starting in November for a study that begins to be performed in January. One of the typical modeling issues to address is how to match expected operational experience with the probabilistic adequacy assessments. The PJM staff takes a lead on this by interfacing with the PJM operational staff and developing technical solutions and options for correlating operational events seen on the bulk power grid with the modeling methods used in the PJM System Planning Division.

The frequency of large PJM generating unit outages for the MAAC region over the summer period was investigated from 1996-2000 and the results are tabulated in Diagram 12. [21, 33, 35] (Analysis for the summers of 2001, 2002 and 2003 is currently being performed). Large units were defined to be those with summer ratings greater than 600 MW. GADS outage events for the ten highest load days for the five year period were extracted and the number of large units out for any reason other than forced was tabulated:

Diagram 12

Year	Number of Large PJM Units Out
1996	3
1997	0
1998	1
1999	0
2000	2

The numbers in the table represent the greatest number of large generating units out on any of the ten highest load days. This number is conservative in the sense that it does not capture the possibility that an even greater number of large units could have been out on any of the other summer days. Based on these results, the standard modeling practice in the Reserve Requirement Study is to schedule one large generating unit out over the summer period for the model that comprises the MAAC region. For a study model twice the size of the MAAC region, as stated as case 3 on page 6, two large units are scheduled out over the summer period.

The proper modeling of generation units requires that any new unit falling under PJM's control area comply with submitting applicable data. This includes reporting using the eGADS web based system and transmittal of telemetry data to the PJM control center. PJM staff is working closely with the market integration companies to ensure that the proper data is obtained and verified in a timely manner.

Summer Maintenance Assessment

One of the activities of the PJM System Planning Division staff is reviewing and summarizing actual dispatcher logs of daily activities over the past year. Of particular interest are the planned outages over the peak summer period. The maintenance outage events of the summer period are reviewed to assess if any market participants are subject to penalty charges. The last several peak period maintenance assessments have indicated 100% compliance and resulted in no penalties for any PJM member. [33, 35]

Benchmarking of Frequency of Voltage Reduction Events

Findings show that PJM has implemented 11 voltage reductions over the last 13 years (1990 - 2002 inclusive). [21, 35] Of these 11, two were for test purposes and occurred at 9 PM and 3 AM. Five of the 11 were due to local transmission problems. That leaves the following four events due to a true system-wide capacity deficiency:

1/19/94 5% Voltage Reduction and Manual Load Dump
5/20/96 5% Voltage Reduction
5/8/00 5% Voltage Reduction
8/9/01 5% Voltage Reduction

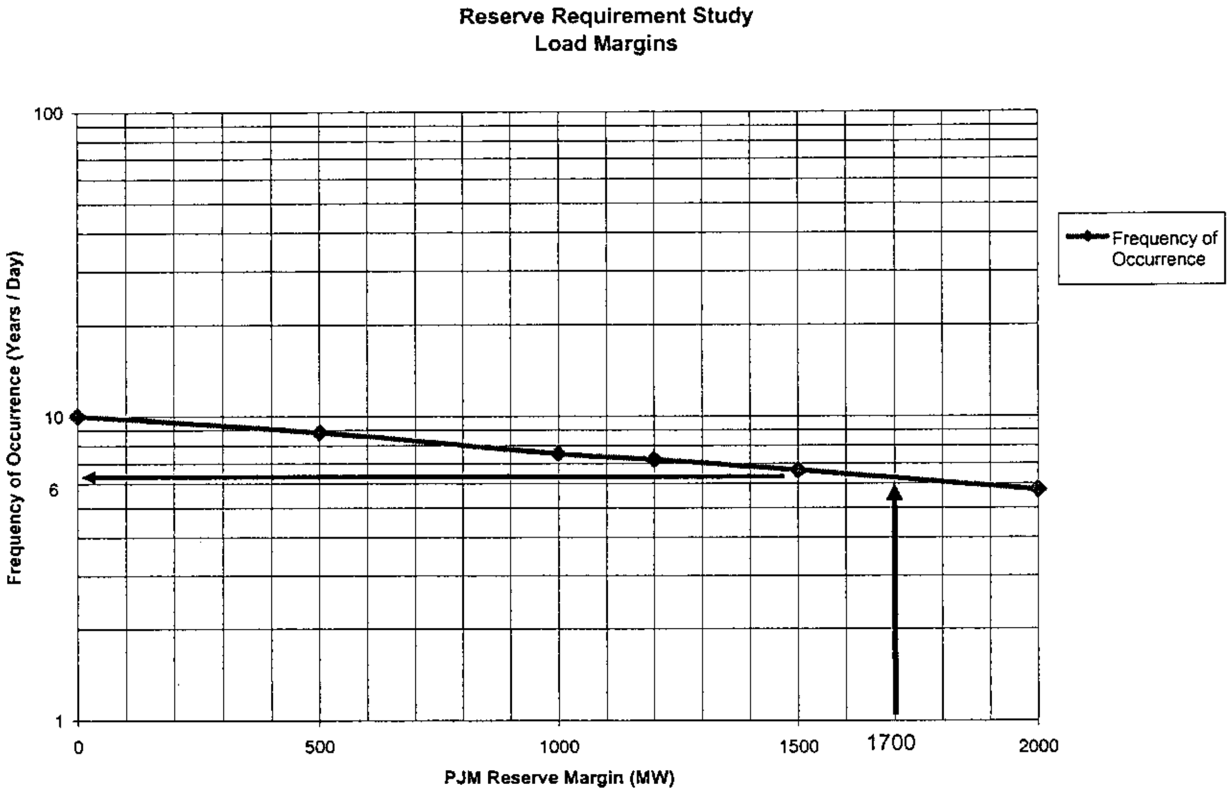
The January 1994 event was due to extraordinary weather conditions which led to a series of common cause failures stemming from fuel unavailability. The risk of common cause failures is not captured in the PRISM model, but work has begun to include this risk in future adequacy studies. That leaves 3 voltage reduction events in 13 years that PRISM would be expected to "predict".

The "1 in 10" criterion refers to the likelihood of having a 0 or negative reserve margin where:

$$\text{reserve margin} = \text{available capacity} - \text{load}$$

Voltage reductions are implemented at positive reserve margins. They are called at the operator's discretion following issuance of a primary reserve alert. A primary reserve alert is generally issued at a reserve margin of about 1700 MW. Voltage reductions are generally implemented when reserve margins drop to between 1200 MW and 1700 MW.

Diagram 13



PRISM analysis was performed to assess how often the adequacy model predicts the occurrence of a primary reserve alert, assuming these events occur at a reserve margin of 1700 MW. Diagram 13 depicts the likelihood of reserve margins ranging from 0 MW to 2000 MW. This diagram indicates the frequency with which a given reserve margin should occur (frequency is on the y axis and is expressed in years per occurrence). The y axis uses a logarithmic scale. The graph indicates that a reserve margin of 1700 MW should occur about once every six years (or twice in 12 years). Three primary reserve alerts (or four including January 1994) have been issued by Operations in the 13 year period from 1990 through 2002. The occurrence of operational events compared to the PRISM results are therefore well within the bounds of sampling error and indicate that PRISM does benchmark well with operating experience.

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Glossary

AEP

American Electric Power, a company and control area within ECAR.

Active Load Management (ALM)

Active Load Management applies to interruptible customers whose load can be interrupted at the request of the PJM OI. Such a request is considered an emergency action and is implemented prior to a voltage reduction.

ALM Factor

Ratio of ALM aggregate Load Carrying Capability (LCC) to total amount of ALM in PJM. The ALM LCC is determined by modeling ALM in the PJM reliability program. The ALM Factor is reviewed and changed, if necessary, each planning period by the Reliability Committee and PJM Board for use in determining the capacity credit for ALM.

APS

Allegheny Power System, a control area within ECAR that was the first portion of expansion of the PJM footprint and markets. Adjacent to the western portion of the MAAC region.

Available Transfer Capability (ATC)

The amount of energy above "base case" conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions. ATC is the First Contingency Incremental Transfer Capability reduced by applicable margins.

Bulk Power Electric Supply System

All generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. Also included are the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area.

Capacity

Ability to deliver both firm energy to load located electrically within the Interconnection and firm energy to the border of the PJM Control Area for receipt by others.

CBM

Capacity Benefit Margin, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect to the PJM Control Area with neighboring regions are evaluated to determine this single value.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a subarea of PJM to satisfy the MAAC "1 in 10" adequacy requirement. This value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the subarea's actual import capability as determined from power flow studies. The subarea satisfies the criteria if its CETL is equal to or exceeds its CETO. CETO/CETL analysis is typically part of the Deliverability demonstration.

ComEd

Commonwealth Edison is a control area within the Mid-America Interconnected Network. The Commonwealth Edison control area is in the state of Illinois principally centered around the Chicago metro area.

Control Area

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Demand

See Load

ECAR

East Central Area Reliability Coordination Agreement. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ECAR Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia, Tennessee, Pennsylvania, and Maryland.

Eastern Interconnection

The bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, bounded on the west by the Rocky Mountains, bounded on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. This is one of the three major interconnections within NERC.

EEFORd

Effective Equivalent Demand Forced Outage Rate. The forced outage rate used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor.

EFORd

Equivalent Demand Forced Outage Rate. The portion of time a unit is in demand, but is unavailable due to a forced outage.

eGADS

Web based Generator Availability Data Systems. Data is collected for both event and performance data in order to track projection of generating units' unavailability as required for PJM adequacy and capacity market calculations. This is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762.

EICS

Emergency Import Capability Studies. A series of power flow studies that assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability.

EMOF

Equivalent Maintenance Outage Factor. For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

ERCOT

Electric Reliability Council of Texas. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ERCOT Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Texas and is one of the three major interconnections within NERC.

FEF

Forecast Error Factor. A value that can be entered in the reliability program PRISM per planning period that indicates the percent increase of uncertainty in the forecasted peak loads. The FEF generally increases 0.5% per year as the planning horizon is lengthened.

FERC

The Federal Energy Regulatory Commission.

FOR

Generating Unit Forced Outage Rate. A statistic based on eGADS event data that indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. There is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand based on weather normalized load techniques. The forecast peak load is an hourly integrated total, in megawatts, indicating the load value given or higher has a 50 % probability of actually occurring.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of "unforced capacity".

FRCC

Florida Reliability Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the FRCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Florida.

GEBGE

See PRISM

Generating Availability Data System (GADS)

A computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

A computer program maintained by the PJM Generator Unavailability Subcommittee that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM OI.

Generator Planned Outage

The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the PJM OI.

Generator Unavailability Subcommittee (GUS)

A PJM subcommittee, reporting to the Planning Committee, that is responsible for computing outage rates and other statistics needed by the Reliability Committee for calculating capacity obligations.

Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include practices, methods, or acts generally accepted in the region.

IRM

Installed Reserve Margin. The percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. Expressed in units of installed capacity.

Load

Integrated hourly energy used either located electrically within the PJM Control Area or delivered to the border of the PJM Control Area for receipt by others. Loads are reported and verified to the tenth of a megawatt (0.1 MW).

Load & Capacity Subcommittee (L&CS)

A PJM subcommittee, reporting to the Planning Committee that assists PJM staff in performing the annual Reserve Requirement Study and maintains the reliability analysis documentation.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that supplies the PJM peak and seasonal load forecasts.

LCC

Load Carrying Capability, typically expressed in megawatts. The amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten year).

LOLE

Generation System Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days per year. This is a measure of how often, on average, the available capacity is expected to fall short of the demand. LOLE is a statistical measure of the frequency of failure and does not quantify the magnitude or duration of failure. The use of LOLE to assess Generation Adequacy is an internationally accepted practice

LOLP

Loss of Load Probability, which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0.

MAAC

The Mid-Atlantic Area Council, a reliability council under §202 of the Federal Power Act, established pursuant to the MAAC Agreement dated August 1994 or any successor.

A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAAC Region through coordinated operations and planning of generation and transmission facilities. The MAAC Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia.

MAIN

Mid-America Interconnected Network. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAIN Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Illinois, Wisconsin, Missouri, and Michigan.

MAPP

Mid-Continent Area Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba.

MMWG

Multi-area Modeling Working Group. The NERC MMWG includes direct representation from the NERC Regions in the Eastern Interconnection, as well as a working group power flow and dynamics coordinator(s), a liaison representative of the NERC staff, and corresponding representatives from the ERCOT and WSCC Regions. The group is charged with the responsibility for developing and maintaining a library of power flow and dynamics base cases for the benefit of NERC members for use by the Regions and their member systems in planning and evaluating future systems and current operating conditions.

MPP

The Most Probable Peak Load is used in the PJM reliability program PRISM. This is the expected weekly peak load corresponding to the 50/50 load forecast based on a sample of 5 weekday peaks.

NERC

The North American Electric Reliability Council, a reliability council responsible for the oversight of regional reliability councils established to ensure the reliability and stability of the regions.

NPCC

Northeast Power Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the NPCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of New York, Main, Vermont, New Hampshire, Connecticut, Rode Island, Massachusetts, Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island.

PC

Planning Committee. A technical committee that is charged with oversight of technical issues in configuration, analysis, planning and operation of the bulk electric power grid in the PJM Control Area. There are technical subcommittees that report to this Committee including: Relay Subcommittee, Load Analysis Subcommittee, Generator Unavailable Subcommittee, Load and Capacity Subcommittee, and Transmission and Substation Design Subcommittee

pcGAR

Personal computer based Generator Availability Report. The pcGAR is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

See Forecast Peak Load

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday.

PJM ISO

PJM Independent System Operator

PJM Open Access Same-Time Information System (PJM OASIS)

The electronic communication system for the collection and dissemination of information about Transmission Services in the PJM Control Area established and operated by the PJM OI in accordance with FERC standards and requirements.

Planning Period

The twelve months beginning June 1 and extending through May 31 of the following year, provided as changing conditions may require, the Reliability Committee may recommend other Planning Periods to the PJM Board of Managers.

PRISM

Probabilistic Reliability Index Study Model. PRISM is the PJM planning reliability program. PRISM replaced GEBGE which was a FORTAN language program. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

Power Flow

Models and studies that determine the power flowing through transmission facilities based on various load and generating unit conditions. Typically, an iterative Newton-Raphson solution technique is used to determine the network flows in the transmission facilities based on Kirchhoff's and Ohm's laws which govern solution convergence.

R.I.

Reliability Index. The reliability index is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years.

RAA (Reliability Assurance Agreement)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. This agreement also defines the role of the RAA Reliability Committee. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff, and the Transmission Owners Agreement.

RAA-RC

Reliability Assurance Agreement Reliability Committee

R-Study

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the R factor, that represents the amount above peak load that must be maintained to meet the MAAC adequacy criteria. The MAAC adequacy criteria is based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years.

SERC

Southeastern Electric Reliability Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SERC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia.

SPP

Southwest Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico.

Weather Normalized Loads

A load adjustment technique approved by the Load Analysis Subcommittee to compensate load data for weather conditions. The adjustment changes the load values to those associated with a 50 / 50 probability of occurrence. (i.e. the load value given or higher has a 50 % probability of actually occurring). This technique is typically associated with forecasting peak load values.

World

Refers to the area electrically connected to the PJM Control Area. Could include ECAR, NPCC and SERC or most of the Eastern Interconnection depending on the study requirements.

ECAR DOCUMENT NO. 8

REQUIREMENTS FOR ACTUAL AND FORECASTED DEMAND AND ENERGY DATA

Approved by the Coordination Review Committee
May 27, 1998

Approved by the ECAR Executive Board
July 27, 1998

East Central Area Reliability Coordination Agreement

Document No. 8

REQUIREMENTS FOR ACTUAL AND FORECASTED DEMAND AND ENERGY DATA

Introduction

This document contains the requirements for member systems reporting of actual and forecasted load data. These data are to be used for analysis of generation adequacy and transmission reliability.

Standards

1. Actual and forecast demands and net energy for load data, required for the analysis of the reliability of the interconnected transmission systems, shall be developed by member systems and maintained by the ECAR Executive Office on an aggregated regional, subregional, power pool, and individual system basis.

2. Interruptible demands and direct control load management programs and data shall be identified and documented.

3. Reported energy and demand data shall exclude generating plant auxiliary load and the load of storage systems of generation suppliers, such as pumped storage hydro plants.

Requirements

1. Member systems shall provide the following data to ECAR, on the schedule and in the format required by the GRP Procedure Manual:

    a. Historical Data – Requirements and Own Ultimate Customer Load

        1) Integrated hourly demands (MW) for the nominal 8,760 hours of the preceding year
        2) Monthly and annual peak demands (MW) and energy (GWh) for the preceding year

    b. Forecasted Data – Requirements and Own Ultimate Customer Load

        1) Monthly peak demand (MW) for ten years beginning with the reporting year assuming that direct-control DSM and interruptible loads are not curtailed.

2) Corresponding demand (MW) of direct-control DSM systems and interruptible loads.

3) Monthly energy (GWh) for two years beginning with the reporting year

4) Annual energy (GWh) for ten years beginning with the reporting year.

c. Forecasted Data - Connected Load (Transmission Providers only)

1) Monthly peak demand (MW) for ten years beginning with the reporting year assuming that direct-control DSM and interruptible loads are not curtailed.

2) Corresponding demand (MW) of direct-controlled DSM systems and interruptible loads.

2. Load data reported to government agencies shall be consistent with that reported to ECAR in compliance with this document.

3. Member systems shall provide the following to ECAR, upon request:

a. Assumptions, methods, and manner of addressing uncertainties in the development of the submitted load forecasts.

b. Documentation of how demand and energy effects of all DSM programs and interruptible loads are addressed.

Reference

NERC Planning Standards (September, 1997) section II.D., System Modeling Data Requirements, Actual and Forecast Demands.

Definitions

Requirements Service – Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning).

Requirements and Own Ultimate Customer Load – This load includes Requirements Service as defined above, plus the reporting party's own ultimate customer load, plus losses.

Connected Load – Connected load is the load served by a Transmission Provider, including the load of Transmission Dependent Utilities (TDUs) and all other ultimate loads on its system, as well as losses. TDU load should be included only to the extent it is served by the Transmission

Provider, excluding offsetting local generation, unless that generation also is to be reported to ECAR.

Direct-control Demand Side Management (DSM) – DSM refers to customer demand that can be curtailed by direct control of the system operator by interruption of power supply to individual appliances or equipment on customer premises.

ECAR DOCUMENT NO. 15

ASSESSMENT OF ECAR-WIDE INSTALLED GENERATING CAPACITY

Approved by the Coordination Review Committee
May 27, 1998
Approved by the ECAR Executive Board
July 27, 1998

East Central Area Reliability Coordination Agreement

Document No. 15

ASSESSMENT OF ECAR-WIDE INSTALLED GENERATING CAPACITY

Introduction

This document requires the submission of data for use in an annual assessment of the adequacy of the projected, aggregate, generating capacity resources in ECAR. It also establishes the criterion to be used in assessing this adequacy. This criterion has been derived for application to the overall ECAR region and is not intended to be utilized for assessing the individual systems in ECAR.

Standards

Data shall be provided so that the overall reliability of ECAR's bulk electric system may be reviewed and assessed, both existing and as planned, to ensure conformance with ECAR planning requirements and with NERC Planning Standards.

Requirements

Members shall submit the following data for a ten-year forecast period, for use in the assessment of ECAR-wide installed generating capacity, in accordance with the GRP Procedure Manual:

1. Forecasted demand data in accordance with ECAR Document 8;

2. Actual and projected generating unit capabilities, service dates, retirement dates, and seasonal ratings (for existing units, data shall be consistent with that reported in response to Document 4); and

3. Schedules of projected firm transactions to supply demand within the ECAR region from sources outside the region or to supply demand outside the region from sources within the region.

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Guides

Experience indicates that for nominal projected conditions, a DSCR index for the ECAR region of one to ten days per year is currently consistent with marginal but satisfactory regional power supply adequacy for the ten-year assessment period.

The calculated DSCR index is the composite of many variables and not the result of action by a single member. Therefore, it is used only to evaluate the overall regional power supply adequacy and to identify unusual situations which may degrade the regional reliability. Reactions to those situations should be taken individually by the member companies of ECAR within their financial, regulatory, and physical constraints and technical ability to respond.

References

NERC Planning Standards (September 1997) Section I.B., System Adequacy and Security, Reliability Assessment.

Definitions

Dependence on Supplemental Capacity Resources (DSCR) – The DSCR index is the number of actual or forecasted days per year that the ECAR region has to rely on: (a) capacity resources outside ECAR; (b) directly controlled load management or interruptible loads within ECAR; or (c) reducing area demand to the extent that such supplemental resources are not available.

The calculation of forecasted DSCR is based on a probabilistic analysis of the capability of the region's generating resources to supply the aggregate total internal demand of the region during daily peak load periods.

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